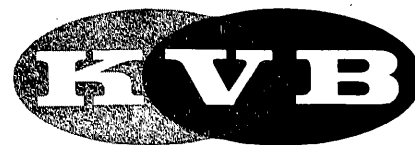


CONTROL OF OXIDES OF SULFUR  
FROM STATIONARY SOURCES  
IN THE SOUTH COAST AIR BASIN  
OF CALIFORNIA



KVB 5802-432

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PREPARED FOR:  
AIR RESOURCES BOARD  
STATE OF CALIFORNIA

PREPARED BY:  
S. C. HUNTER  
N. L. HELGESON  
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KVB, INC.

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## ABSTRACT

A comprehensive inventory has been taken of oxides of sulfur (SOx) emissions from stationary sources in the South Coast Air Basin of California in 1974. Emissions from over 1580 point sources were assessed from detailed device and fuel use information provided by device operators and local air pollution control districts. Tests to verify the inventory were conducted on 38 devices that emit SOx in the Basin.

Sulfur oxide emissions were estimated to be 342 tons per day on an annual average basis in 1974. This was lower by about 22% compared with 1973 as the result of reduced energy demand. Emissions in August 1974 were lower than the annual average but, compared with previous summers, emissions were increased as the result of curtailed natural gas supplies being replaced with low sulfur fuel oil.

Power plants were the dominant source category, followed by refineries and carbon plants and a variety of smaller sources. Emissions from stationary sources are much larger than emissions from mobile sources on an overall basis. Local effects and effects of mobile catalytic converters on total SOx and sulfuric acid mist are assessed in comparison with stationary sources.

Forecasts made to 1980 indicate substantial increases over 1974 emissions as the result of increased fuel oil burning. This will occur in spite of large reductions in refinery sulfur recovery plant emissions. Power plants will burn the major portion of this oil but other oil burning devices are becoming increasingly significant.

Air quality standards for particulate matter and visibility are being exceeded in the basin, in part as the result of formation of sulfates from SOx. Gaseous SO<sub>2</sub> air quality standards are also being exceeded but to a much lesser degree. It was not possible in this program to define the specific effects of stationary source SOx emissions on air quality nor to establish any limitations in these emissions that may be necessary to meet the standards. However, should further control of stationary sources be found necessary, the costs and effectiveness of potential reduction methods based on existing technology have been estimated for the most significant sources.

Limitation of fuel oil use is the most effective control in terms of total reductions achievable. Securing substantial increases in natural gas supplies or power from outside the basin are the primary ways of achieving this limitation. Most other options for SO<sub>x</sub> control that were examined are expected to be more costly than existing controls.

#### ACKNOWLEDGEMENT

KVB, Inc., in compiling the data presented herein, was assisted by many people in industry and government agencies. Of particular help were members of the Los Angeles County Air Pollution Control District and the California Air Resource Board Staff. Industries that contributed included the electric utilities, petroleum refineries, operators of petroleum coke kilns, glass plants, sulfuric acid plants, metals plants, and cement plants.

KVB, Inc. extends its appreciation to those who contributed, but takes full responsibility for assembly of the data, conclusions drawn therefrom and for any errors involved.

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## 1.0 INTRODUCTION

Curtailement of natural gas deliveries in California has sharply increased and it is anticipated that there will be a continuing shortage in the near future. This has resulted in increased use of low sulfur oil in place of natural gas and increased pressure to use higher sulfur oils. Concurrently, the introduction of catalyst emission controls on motor vehicles is believed to change the character of sulfur emissions from these sources. The impact of these events will result in increased oxides of sulfur emissions and rapid changes in the relative amounts of sulfur oxide compound types emitted from stationary and mobile sources.

Control of emissions at the state level has focused primarily on mobile sources and information on stationary sources is required for continued assessment of mobile source controls to ensure that controls are effective and necessary. Furthermore, as the achievement of overall air quality standards is the purpose of all emissions regulations and as mobile sources are further reduced, it is evident that public and legislative attention will shift toward more concentrated consideration of the need for and feasibility of regulations at the state level for stationary sources. California is unique in that it is the only state in which primarily regulatory responsibility for stationary source emissions rests with local (primarily county) agencies rather than a state agency. This is a result of the pioneering efforts in air pollution control by the Los Angeles County Air Pollution Control District. Substantial reductions in emissions have been achieved by the various local agencies. Increased activity at the state level, whether by direct regulations or implemented through local agencies, will require information to guide evaluation of present and future alternative control options to achieve the best overall cost effective control of all sources.

Anticipating this shift of attention, the California Air Resources Board is supporting a comprehensive research project to develop information on stationary sources of oxides of sulfur emissions. An inventory is required that will identify all domestic, commercial, industrial, institutional, and public utility sources of oxides of sulfur (SOx)

in the South Coast Air Basin. Data are to be provided on source location, amount of emissions in both concentration and mass units, and cyclic variations of day, season, or process. Accuracy of the inventory is to be confirmed with measurements of emissions from selected sources. Each type of source is to be evaluated to establish potentials for reductions that could be achieved by application of present control technology and the costs associated with these reductions.

This report presents the results of a program directed to provide the information required for the Board's objectives. The approach employed was to establish a preliminary source inventory of SOx emissions as a means of identifying the most significant sources and any uncertainties that exist in current emissions information. The confidence in the emission inventory was improved with a source test program of selected devices and collection of additional operational data. A forecast of future SOx emissions was provided and potentials for SOx emissions reduction were assessed for application of existing reduction technology on a cost effective basis.

Inventories of SOx emissions for the South Coast Air Basin have previously been compiled by county, state and federal agencies. An objective of the current program was to compile an inventory with the following improvements over existing inventories:

1. Use of uniform computation methods for all devices in all counties of the Basin.
2. Extension of the devices included to a lower level of emission rate.
3. Determination of seasonal emission characteristics in addition to annual rates.
4. Attempt to refine the characterization of device operational patterns and relative capacities.
5. Provide geographical distributions of source emissions.
6. Assemble the data in an inexpensive electronic data processing system to facilitate desired sorts, summations and updates.

In refining the preliminary emissions inventory, operational and material use data were gathered by questionnaire forms from 39 major material processing companies and an eleven-week field test program was conducted during which 38 source tests were conducted. Extensive use was made of data gathered during a study similar to the current program but directed to NOx emissions (Ref. 1).

Emissions of sulfur oxides occur as the result of two broad groups of activity: the combustion of fuels and the processing of various sulfur-bearing industrial materials. The characteristics of these sources as related to oxides of sulfur emissions are discussed in Section 2.0.

There has been a distinct seasonal variation in sulfur oxides emissions in recent years with low emissions in the summer as the result of substantially increased natural gas supply to the electric utilities beginning about 1967. In 1970, gas use reached a maximum and supplies began to dwindle in 1971, but utilities were still able to burn mostly gas in the summer. This came to an abrupt halt in 1974 when less than 50% of summer energy was supplied by gas. The means employed to reflect these trends on the inventory of stationary source emission rates and the selection of 1974 as the inventory period are discussed in Section 3.0.

Substantial effort by federal, state and local air quality control agencies has already been expended in understanding the sources and levels of various emissions. As a basic approach to conducting this program, maximum use was made of data already available and the sources of these data are discussed in Section 4.0.

As a means of verification of the inventory, tests of 38 material processing devices in the Basin were conducted in eight oil refineries; one petroleum coke plant; two sulfuric acid plants; two steel mills, one each iron and lead metal mills; five glass plants; one each cement, gypsum, and brakeshoe; and one oil field. The rationale for selection of these sources is discussed in Section 5.0. Test methods used and results obtained are detailed in Appendix D.

From a compilation of 1583 separate potential SOx emission sources, and with application of the data gathered, it was found that emissions of SOx were about 342 tons/day in 1974 on an annual basis. These emissions were down about 22% from 1973 and about equal to the 1970 level, as the result of a combination of the energy shortage and significant imports of hydroelectric power. Section 6.0 presents the inventory of the emissions in 1974 as emitted by various devices, industries and on a geographic and seasonal basis.

As a curious consequence of the same energy crises that was partially responsible for reduced 1974 annual emissions, SOx emissions in the summer of 1974 experienced a sharp increase. From an estimated range of 140 to 200 tons/day in past years when gas was plentiful and oil burning restricted to winter months, the summer emissions have increased to an estimated average of 305 tons per day during August 1974. This increase foreshadows substantial projected increases in all months of future years, but most dramatic growth will occur in the summer. Section 7.0 presents the results of projections, indicating a growth to about 740 tons/day throughout the year by 1980 assuming that energy demands can continue to be met with low sulfur fuel oils. The current status of air quality is briefly reviewed in relation to current and projected SOx emissions.

It was not possible to provide a definitive criteria for SOx control in terms of air quality. However, should it be found necessary to impose more stringent controls, Section 8.0 presents a comparison of the cost effectiveness of various potential SOx emissions reduction methods based on existing control technology.

Conclusions drawn from the inventory, projections and assessment of potential reduction methods are summarized in Section 9.0 and references cited are listed in Section 10.

Appendices A-E deal with the computation procedures, data format, preliminary inventory, test results, and point source data questionnaire. Appendix F presents an analysis of SOx reduction through desulfurization of fuel oils and costs associated. Appendices G-M present data specific to particular sources. Appendix N presents an analysis of gas supplies.

## 2.0 SOx EMISSION SOURCES

Emissions of sulfur compounds from stationary sources occur as the result of two broad groups of activity: the combustion of fuels and the processing of raw materials that contain sulfur. This section discusses the various processes by which sulfur is released to form sulfur oxides in the gas streams exhausted to the atmosphere. Only those processes of specific importance to the South Coast Air Basin are discussed.

Regulations have been promulgated to limit SOx emissions from certain stationary sources. Table 2-I is a tabulation of the regulations currently in force in the six counties of the South Coast Air Basin.

### 2.1 Combustion Sources of SOx

Sulfur is present in some form in most common fuels, whether solid, liquid or gas. The only solid fuels of interest in the South Coast Air Basin are coal and coke employed in steel manufacturing and being introduced in cement plants. These uses are discussed in Section 2.2 on material processing.

Combustion of liquid fuels constitutes the largest stationary source of Basin SOx emissions with utility power plant boilers having the largest use of liquid fuels. This fact has been long recognized by regulatory agencies and sulfur content of nearly all liquid fuels burned in the Basin is limited to 0.5% sulfur by weight. The predominant utility liquid fuel is residual oil and, in the absence of regulations, could range up to 2% or more in sulfur content. However, current usage is limited to low sulfur residual oils and sulfur contents range between 0.4 and 0.5% sulfur. Distillate oils, used by many industries when natural gas is unavailable, range from 0.01 to 0.5% sulfur by weight. Gasoline used primarily in motor vehicles and to a very minor extent by industry is typically 0.02 to 0.06% sulfur by weight. Other liquid fuels such as propane, butane and liquified petroleum gas contain negligible amounts of sulfur.

TABLE 2-I

## SOUTH COAST AIR BASIN SOX EMISSIONS REGULATIONS

EPA Federal		Los Angeles County	Orange County	San Bernardino County	Riverside County	Santa Barbara County	Ventura County	Southern Calif. APCD
OXIDES OF SULFUR New Sources	Rule Date Limit	67 1/1/72 200 #/hr	67 1/1/72 200 #/hr	67 1/1/72 200 #/hr	72 (West Central) 1/1/72 200 #/hr	39 1/1/72 200 #/hr	60 9/29/70 200 #/hr	
	60.43 12/23/71 .8 #/106 Btu (oil) 1.2 #/106 Btu (gas)							
SULFUR COMPOUNDS (Expressed as SO <sub>2</sub> unless noted)	Rule Date Limit	53 -- by vol.	53 -- by vol.	53 -- by vol.	53 -- by vol. (West Central)	19 1/1/72 .2% by vol.	54 1/1/74 300 ppm (Comb) 500 ppm (Other) 10 ppm H <sub>2</sub> S	
	All Sources							
Sulfur Recovery Units	Rule Date Limit	53.2 6/30/73 500 ppm 10 ppm H <sub>2</sub> S 200 #/hr	53.2 -- 500 ppm 10 ppm H <sub>2</sub> S 200 #/hr	53A 1/1/72 (Exist) 1/1/75 (New) 500 ppm vol.	56.1 -- 500 ppm 10 ppm H <sub>2</sub> S 200 #/hr	20.1 1/1/72 500 ppm 10 ppm H <sub>2</sub> S 200 #/hr		468 5/7/76 500 ppm 10 ppm H <sub>2</sub> S 90 kg/hr
	Sulfuric Acid Units	53.3 12/31/73 500 ppm 200 #/hr	53.3 -- 500 ppm 200 #/hr	53.3 1/1/75 500 ppm 200 #/hr	56.2 -- 500 ppm 200 #/hr	20.2 1/1/72 500 ppm 200 #/hr		469 5/7/76 500 ppm 90 kg/hr
FUEL SULFUR CONTENT	Rule Date	62 --	62 --	62 <sup>+</sup> --	64 <sup>++</sup> --	32 --	64 1/1/74	431 5/7/76
	Limit - Natural Gas Limit - Other Gas Limit - Liquid/Solid	50 gr H <sub>2</sub> S/100 CF 50 gr H <sub>2</sub> S/100 CF .5% S wt	15 gr H <sub>2</sub> S/100 CF 50 gr H <sub>2</sub> S/100 CF .5% S wt	15 gr H <sub>2</sub> S/100 CF* 50 gr H <sub>2</sub> S/100 CF .5% S wt *Rule 62.1	15 gr H <sub>2</sub> S/100 CF* 50 gr H <sub>2</sub> S/100 CF .5% S wt *Rule 64.1	15 gr H <sub>2</sub> S/100 CF 15 gr H <sub>2</sub> S/100 CF .5% S wt	15 gr H <sub>2</sub> S/100 CF 50 gr H <sub>2</sub> S/100 CF .5% S wt	800 ppm H <sub>2</sub> S 800 ppm H <sub>2</sub> S .5% S wt
PARTICULATE MATTER (SO <sub>3</sub> acid mist)	Rule	52	52	52	52	18A	52	
	Limit - Non-Comb. Rule Limit - New Fuel Burn	0.01-0.2 gr/CF 67 10#/hr	0.01-0.2 gr/CF 67 10#/hr	0.01-0.2 gr/CF 67 10#/hr	0.01-0.2 gr/CF 72 10#/hr 72.1	0.01-0.2 gr/CF 39 10#/hr	0.01-0.2 gr/CF 60 10#/hr 57	475 5 kg/hr 409 0.23 g/cm, 12% CO <sub>2</sub>

\* Allows alternate control equal 0.5% S oil. ++ Allows alternate control equal 50 gr H<sub>2</sub>S/100 CF gas.

Burning of liquid fuels in an excess of air is invariably found to result in release of the entire sulfur content to form sulfur dioxide ( $\text{SO}_2$ ). The reaction forming  $\text{SO}_2$  occurs in a time of the same order as the combustion of carbon and hydrogen to form  $\text{CO}_2$  and  $\text{H}_2\text{O}$  (Ref. 2) so that little can be done in the way of combustion control to prevent  $\text{SO}_2$  formation. A small portion of the sulfur can form sulfates in the ash and this may be of importance in particulate emissions but the quantity involved is negligible compared with the gaseous emissions of  $\text{SO}_2$ .

Cooling of the exhaust gases and catalytic action on the equipment or particulate surfaces can result in conversion of a portion of the  $\text{SO}_2$  to sulfur trioxide ( $\text{SO}_3$ ). The amount of  $\text{SO}_3$  formed varies from less than 1% by volume of the total  $\text{SO}_x$  to as high as 13% (Ref. 3) but typically the amount is in the range of 1 to 3%. Values typically observed for boilers are shown in Figure 2-1. At temperatures below  $500^\circ\text{F}$  thermodynamic equilibrium provides that all of the sulfur could be converted to  $\text{SO}_3$ . Theoretical equilibrium conversion of  $\text{SO}_2$  to  $\text{SO}_3$ , shown in Figure 2-2 indicates  $\text{SO}_3$  decreases with temperature. The effects of temperature on chemical kinetic reaction rates are such that  $\text{SO}_3$  is observed to be low at low temperatures with peak conversion occurring in the range of  $800$ - $1500^\circ\text{F}$ . The amount of  $\text{SO}_3$  formed is related to fuel sulfur content, excess air, and the gas cooling process. When stack temperatures are reduced below  $300$  to  $400^\circ\text{F}$ ,  $\text{SO}_3$  can be converted to  $\text{H}_2\text{SO}_4$  or  $\text{H}_2\text{SO}_4 \cdot 2\text{H}_2\text{O}$  with resultant sulfuric acid mist emission.

The combustion of gaseous fuels in the Basin includes the use of natural gas in most all types of combustion devices and refinery gas in oil refinery process heaters and boilers. Other gaseous fuels such as coke oven gas and blast furnace gas are used in much smaller quantities. Regulations generally limit natural gas sulfur content to a maximum of 15 grains of sulfur compounds expressed as  $\text{H}_2\text{S}$  per 100 cubic feet of gas. In some counties up to 50 grains  $\text{H}_2\text{S}/100$  CF are allowed. Typical natural gas in the Basin is well below these limits

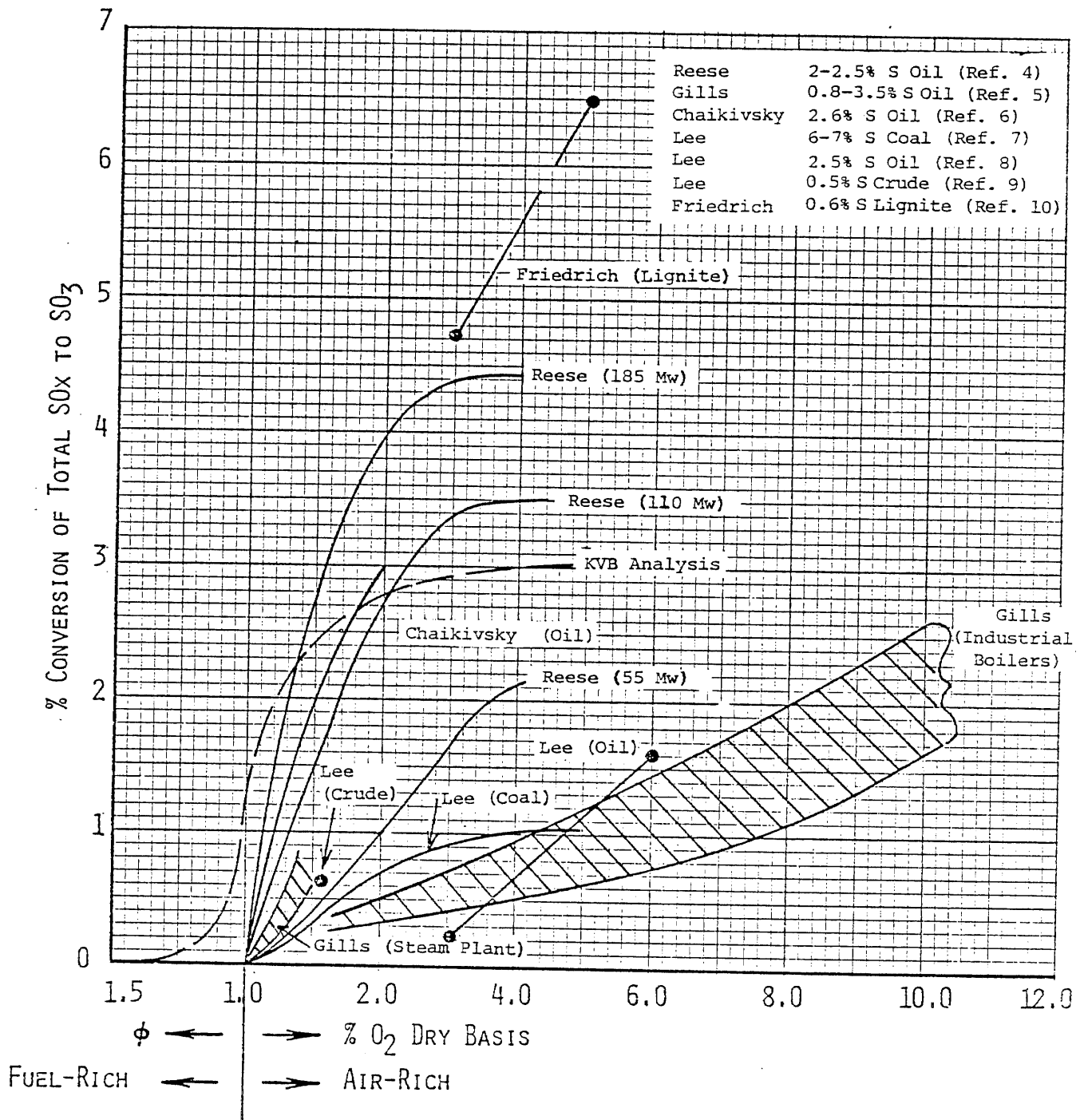


FIGURE 2-1. EFFECT OF FUEL-AIR MIXTURE RATIO ON SO<sub>3</sub> PERCENT CONVERSION.



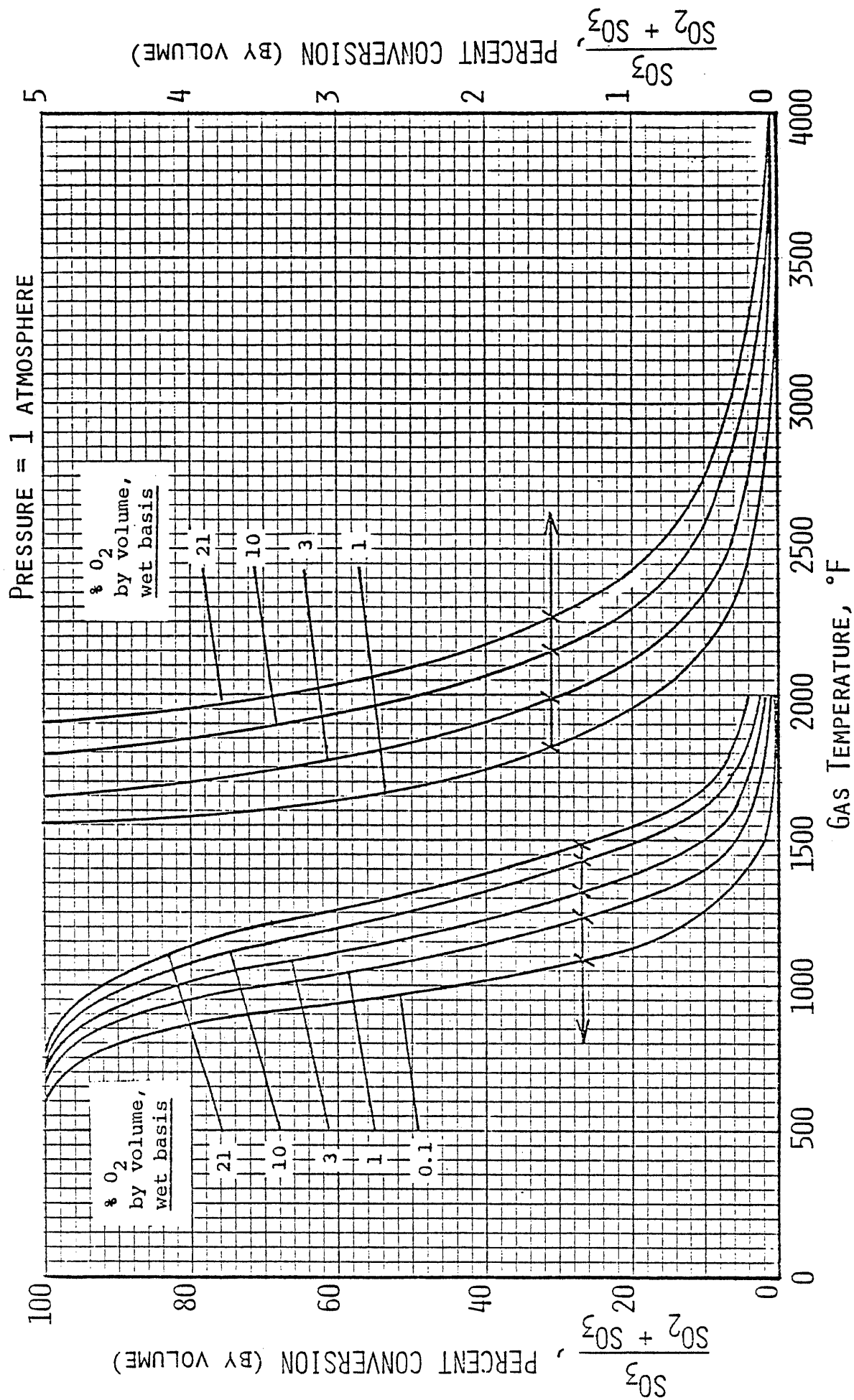


FIGURE 2-2. THERMODYNAMIC EQUILIBRIUM CONVERSION OF  $SO_2$  TO  $SO_3$ .

5802-432

ranging from 0.2 to 0.5 grains of  $H_2S/100$  CF and averaging about 0.3 (Ref. 11). Some of this sulfur occurs naturally in the gas and some results from addition of mercaptan compounds and other sulfur compounds as required to meet odor detectability. These sulfur contents are lower than liquid fuel contents by an order of about 1/500. For example 0.3 grains  $H_2S/100$  CF in natural gas is equivalent to 0.0009% sulfur by weight as compared with 0.4% sulfur typical for low sulfur oils.

Refinery gas as reported to the Los Angeles County Air Pollution Control District (Ref. 12) ranges from 0.07 to 40 grains  $H_2S/100$  CF with average for all refineries of 7 grains  $H_2S/100$  CF. Thus emissions per cubic foot burned will be higher than for natural gas but still well below that of oil fuels since 7 grains  $H_2S/100$  CF is approximately equivalent to 0.016% S by weight.

Other gases burned are primarily process generated and may have much higher sulfur contents than either natural or refinery gases. Quantities burned are small but must be accounted for.

As with liquid fuels all of the sulfur in the gaseous fuel is converted to  $SO_2$  during the combustion process. Conversion to  $SO_3$  can occur in a similar manner as with liquid fuels. However because of the low sulfur content the  $SO_3$  concentrations will be below measurable limits and can be neglected.

## 2.2 Material Processing Sources of $SO_x$

Sulfur is present in various forms in many of the raw materials utilized in industrial processes. Processes that result in melting, drying, burning and chemical reaction of the raw materials can result in part or all of the sulfur being released to the exhaust gases. The amount of sulfur oxides formed can be expected to be related to the sulfur content of the raw materials. The presence of excess oxygen and high temperatures can result in conversion of the sulfur released to sulfur oxides. However the presence of particulates in the exhaust and various types of equipment employed to remove particulates can influence the amount and composition of the sulfur that is finally

emitted to the atmosphere. In addition sulfur can be reabsorbed in the processed materials. It is therefore difficult to inventory emissions from material processing devices without specific test data on each particular process and a knowledge of the process chemistry and operations.

The major potential sources of SO<sub>x</sub> emissions from material processing in the Basin are related primarily to petroleum refining and related industries, and manufacturing of metals, construction aggregate, glass, and gypsum processing.

Sources related to the petroleum industry include regeneration of catalysts used in catalytic cracking, recovery of sulfur from various desulfurization processes, processing of petroleum coke, manufacturing of sulfuric acid, and burning of H<sub>2</sub>S gas in oil field operations.

In large petroleum refineries approximately 25 to 40% of the refinery product is processed by means of a fluid catalytic cracking unit (Ref. 13). Vacuum gas oil from vacuum distillation of the heaviest portion of the crude feed and some recycled product is passed to a fluidized bed reactor. The feed is mixed and fluidized with catalyst powder to accelerate cracking of the heavy oil molecules to lighter molecules. During the cracking process coke is deposited on the catalyst powder. This coke contains sulfur in amounts related but not necessarily equal to that in the feed (Ref. 14) and the presence of the coke tends to deactivate the catalyst. Reactivation of the catalyst is performed in a regenerator where air is added in quantities sufficient to burn the hydrogen to H<sub>2</sub>O, the sulfur to SO<sub>2</sub> and the carbon to CO and CO<sub>2</sub> in approximately equal volume amounts. Carbon combustion to CO<sub>2</sub> is limited to limit regenerator temperatures to prevent catalyst glazing but some newer processes and catalysts are being developed to allow complete carbon combustion (Ref. 15). In conventional high CO units the combustion product gases are generally passed through a waste heat boiler to complete the CO to CO<sub>2</sub> combustion and to generate process steam. Additional fuel may be burned in the boiler to sustain the CO flame and may add additional sulfur. Electrostatic precipitators are

frequently used either before or after the CO boiler. Since essentially complete combustion of the catalyst coke can be assumed (Ref. 14) the SOx emissions can be related directly to the coke sulfur content and coke production rate plus sulfur in any additional fuel burned in the boiler. However, the amount of coke formed and the fraction of feed sulfur contained in the coke is a very complex function of feed properties and process operation.

Various refinery processes are operated to remove sulfur from the products and from refinery gas burned for process heat. The primary form of the sulfur is in acid gases as H<sub>2</sub>S and as such is of no commercial value. In the absence of processes for conversion of H<sub>2</sub>S to commercial products, this gas would have to be burned in waste gas flares with large emissions of SOx. Conversion of the H<sub>2</sub>S to salable pure sulfur or sulfuric acid represent steps taken by the refineries that have resulted in reduced SOx emissions.

H<sub>2</sub>S gas is converted to pure sulfur by the Claus process. Approximately 1/3 of the H<sub>2</sub>S is burned in a furnace with air to form SO<sub>2</sub> and water. The remaining H<sub>2</sub>S and SO<sub>2</sub> formed is reacted over a catalyst to produce water and sulfur that is then condensed to a solid. The chemical reactions of this two-step process are:



Maximum sulfur production (and minimum emission) is obtained when the volume ratio of H<sub>2</sub>S to SO<sub>2</sub> is at the stoichiometrically correct ratio of 2/1 during the second stage process of reaction 2-2. Temperature conditions for reaction 2-2 are such that complete conversion to sulfur is not achieved and the exhaust gases, after condensation of the sulfur, still contain H<sub>2</sub>S, SO<sub>2</sub>, and some sulfur vapor. Because the original H<sub>2</sub>S feed gas generally contains hydrocarbon and CO<sub>2</sub> impurities the exhaust can contain COS and CS<sub>2</sub>. Incineration may be performed to convert all the various compounds to SO<sub>2</sub> and CO<sub>2</sub> plus

some  $\text{SO}_3$  or  $\text{H}_2\text{SO}_4$ . Conversion of the typical Claus plant is 90 to 96% of the inlet sulfur converted to sulfur product (Ref. 16). The unconverted sulfur results in large concentrations of  $\text{SO}_2$  and tail gas  $\text{SO}_2$  extraction units have been installed on all Claus plants in the Basin for compliance with Los Angeles County APCD Rule 53.2 limiting  $\text{SOx}$  to 500 ppm and  $\text{H}_2\text{S}$  to 10 ppm. (SCAPCD Rule 468)

Petroleum coke is a byproduct of the refining process and is converted to carbon in large fired rotary calcining kilns. Although the coke is not burned the high temperature involved can result in release of sulfur from the coke which contains up to 2% sulfur by weight. The coke sulfur and sulfur in the fuel produce stack emissions of  $\text{SO}_2$  and some  $\text{SO}_3$ . Coke kiln stack temperatures are between 1700 and 2200°F and sufficient time may be available for the amount of  $\text{SO}_3$  to obtain near equilibrium values of 1 to 8% by volume of the total  $\text{SOx}$ .

Sulfuric acid is manufactured from refinery waste product acid gas containing  $\text{H}_2\text{S}$ , spent acid, and molten sulfur. Input materials are burned with air in a furnace to produce  $\text{SO}_2$ . The  $\text{SO}_2$  is passed through a catalytic converter for conversion to  $\text{SO}_3$ . The  $\text{SO}_3$  is then absorbed in sulfuric acid and converted to sulfuric acid product. Single stage converters result in 90 to 95 percent conversion of the feed sulfur to acid. Conversion efficiency can be improved by double stages of both conversion and absorption to reduce emissions and increase production. Scrubbers, precipitators and mist eliminators are used for further reduction of emissions. Emitted oxides of sulfur are as  $\text{SO}_2$  and acid mist.

The final source related to petroleum processing is the burning of waste gas containing  $\text{H}_2\text{S}$  that is formed in oil field operations. Burners called vapor phase reactors are used to incinerate the  $\text{H}_2\text{S}$  to  $\text{SO}_2$ .

Sources of SOx related to processing in the metals industry include primarily steel manufacturing and lead operations. Sources in steel plants include coke making, sintering operations, and various furnaces. Coke operations involve the conversion of coal to metallurgical coke and emissions of SOx result from coke ovens and coke quench towers. Coke oven batteries are charged with coal which is heated in the absence of air to form coke. Coke oven gas is driven off and used as a fuel to fire the ovens and other devices. Blast furnace gas may also be used for fuel. Sulfur in the coal is converted to  $H_2S$  during generation of coke oven gas and is burned to  $SO_2$  during firing to heat the ovens. Although the coke oven gas is a fuel the SOx emitted is the result of coal processing and for the purpose of the current inventory this source is considered as a process source rather than a fuel source. Additional SOx is emitted when the coke is removed from the ovens and quenched with water in coke quench towers.

The production of pig iron from iron ore first involves a sintering process where ore is mixed with coke and ignited on a traveling bed to produce agglomerate particles for charging into a blast furnace. Sulfur in the coke is the primary source of SOx in this process but some sulfur in the form of  $FeS_2$ , iron pyrite, present in the ore may be an additional source. The source of iron ore for Basin steel production is the Eagle Mine in Riverside County (Ref. 17). Following the sinter formation, the sinter and additional materials including coke are charged in blast furnaces and melted to produce pig iron. The burning of the coke results in formation of CO and  $SO_2$ . The blast furnace gas is used as a fuel in blast furnace air preheating stoves and in plant boilers. Emissions of SOx can arise from the blast furnace stoves but none are emitted from the blast furnace itself.

Open hearth furnaces melt pig iron and/or scrap steel and are heated with gas or oil fuels. SOx emissions are primarily due to the fuel although petroleum coke containing sulfur and possible sulfur in the charge materials may provide additional sources. Steel plant

boilers burn various fuels including coke oven and blast furnaces gas. These devices are included in the group of fuel burning devices as SOx emissions are not primary the result of material processing.

Other SOx sources in the metals industry relate primarily to lead processing. The lead industry employs blast and reverberatory furnaces for the reclaiming of lead from auto batteries. Sulfur in the lead battery plates, from residual sulfuric acid and coke added can be released to form  $\text{SO}_2$ . The reclaiming process is also performed in lead sweating furnaces. Sweating is a process of low temperature selective melting for recovery of lead from scrap.

Lightweight construction aggregate is manufactured by heating shale in a rotary kiln. The shale is primarily silica but may contain gypsum (hydrated  $\text{CaSO}_4$ ). During heating moisture is driven off and some sulfur may be released by decomposition of the gypsum.

In glass manufacturing, sand, lime ( $\text{CaO}$ ), soda ash ( $\text{Na}_2\text{CO}_3$ ), salt cake ( $\text{Na}_2\text{SO}_4$ ), barium sulfate ( $\text{BaSO}_4$ ), iron pyrite ( $\text{FeS}_2$ ) and other compounds are mixed in specific amounts and charged into a regenerative open hearth furnace, melted and withdrawn to form glass products. Soda-lime glass is the type of glass produced in most of the Basin glass furnaces. There are three main types of soda-lime glass: flint (clear), amber and green. The major use of these glasses is for beverage bottles. Salt cake, barium sulfate, and iron pyrite are the major process sources of sulfur oxides and are used in varying amounts for each of the three types of glass. Larger quantities of salt cake are required for the color glass types (amber and green) as compared with flint glass. Therefore SOx emissions from color glass furnaces can be higher than from those making flint glass. This distinction is necessary in developing emission factors as all glass furnaces may not be adequately represented by a single average SOx emission factor. The salt cake is not a primary ingredient of the glass but serves as a fluxing agent for prevention of scum formation

on top of the molten glass pool. The salt cake is oxidized to  $\text{Na}_2\text{O}$  that remains in the glass and part of the sulfur is released to form  $\text{SO}_2$  in the exhaust. Baghouses and scrubbers are frequently used for particulate control and may have some influence on emissions of  $\text{SO}_2$  and  $\text{SO}_3$ .

A possible source of  $\text{SOx}$  emissions is from cement manufacturing. Any gypsum present in the raw materials could result in sulfur release. However, some sulfur must be retained in the mix for proper cement production. It is believed that any sulfur that is emitted is in particulate form as calcium sulfate and removed by baghouses and little if any free  $\text{SOx}$  is emitted to the atmosphere even from fuel combustion.

Calcining of gypsum for use in manufacture of plaster of paris for building wall board could be a possible source of  $\text{SOx}$ . Calcining involves heating the gypsum to drive off water and is done at low temperatures below the point at which the gypsum would decompose to form  $\text{SOx}$ . Program tests showed that sulfur is released only as particulates of calcium sulfate and, as with the cement plants, most of this material is removed by stack gas treatment with negligible emissions of  $\text{SOx}$ .

Definition of the foregoing possible sources of  $\text{SOx}$  forms the basis for review and testing of the various devices noted as a means of ensuring the most complete inventory possible.



### 3.0 EMISSION RATE DEFINITION AND INVENTORY PERIOD SELECTION

Traditionally emissions inventories express emissions of a source in terms of tons emitted per year or average day. The tonnage is expressed in terms of a specific chemical compound such as  $\text{SO}_2$  or  $\text{NO}_2$ . The methods for obtaining inventoried values range from simple conversion of source test hourly rates to a detailed accounting of actual operating conditions over a typical day or year. The annual rate has been adopted as the standard by the EPA (Ref. 18). Hence this is one of the values included in the present  $\text{SO}_x$  inventory and is computed to reflect typical operating time and fraction of rated capacity. Since air quality deterioration generally occurs during a period of a few days of stable inversion the annual emissions presented in this inventory are expressed on a daily basis rather than for a whole year. This average is obtained from an integrated annual emission in tons of  $\text{SO}_x$  as  $\text{SO}_2$  per year divided by 365 days.

The annual average emissions, while useful for comparison with other inventories may not adequately relate to air quality deterioration events. For certain sources the emissions can vary substantially with seasonal changes in fuel usage. The predominant seasonal effect in  $\text{SO}_x$  emissions from large industrial and utility fuel burning devices relates to the use of gas fuel during summer months and oil fuel during winter months. For this equipment peak gas use occurs in July or August while peak oil use occurs in December or January. This is in contrast to total gas use in the basin which reaches a peak in the winter months as the result of space heating requirements. The seasonal pattern for industrial and utility gas use is the result of the relative price of natural gas compared to fuel oil and to seasonal gas availability. Gas is burned in the summer and replaced with fuel oil when gas supply to interruptible users is curtailed to provide available gas supplies for space heating. Thus summer and winter daily emissions are of direct interest in an inventory concentrating on the South Coast Air Basin where atmospheric conditions are somewhat unusual. Accordingly, in addition to the annual average daily emissions, emissions have been inventoried for typical operation during August and December with proper accounting for fuel use patterns.

The base period for this inventory was selected as the calendar year 1974. A previous inventory for NOx emissions (Ref. 1), from which much of the information for the current inventory was obtained, was based on the fiscal year July 1972 to June 1973. Since most other inventories are based on the calendar year this made comparison difficult and a change to the calendar year basis will resolve that problem. The calendar year 1974 was selected not only because it is the most recent year but because there were substantial changes in SOx emissions during 1973 as the result of implementation of Rules 53.2 and 53.3 on July 31, 1973 in Los Angeles County for sulfur recovery and sulfuric acid plants. In addition the rapid decrease in gas fuel availability is resulting in significant changes in the seasonal emission patterns that quickly render inventories obsolete.

In compiling the emissions inventory two distinct types of SOx sources must be considered: those devices where SOx emissions results only from combustion of sulfur-bearing fuels, and those devices that process sulfur-containing materials from which part or all of the sulfur is released to the exhaust.

For combustion devices where fuel is the only source of SOx, the emissions are computed directly from the fuel use assuming 100% of sulfur as SOx. This procedure has been confirmed in numerous tests for liquid and gaseous fuels. For solid fuels some sulfur remains in the ash but such fuels are rarely used in the Basin.

For combustion devices information is required only for the fuel burning rates and detailed consideration of the device operating process is unnecessary. For devices that process sulfur-bearing materials or materials that can absorb sulfur, emission factors can be used to relate the SOx emissions to the quantity of material in a manner similar to fuel use. Emission factors have been derived by the EPA (Refs. 19, 20) for many processes. The limitations and applicability of emission factors must be considered because in general

emission factors are not necessarily precise indicators of emissions from a single source, but represent averages from a large number of sources. These factors are generally expressed as pounds of SO<sub>x</sub> emitted as SO<sub>2</sub> per short ton (2000 pounds) of material processed. Care must be taken to identify process weights as short or long tons (2240 pounds). Ratings of sulfur recovery plants are normally expressed in long tons of product.

For the current program emission factors in the form defined by the EPA are used and test results are reduced to this form to facilitate comparison. Inventory emissions for a particular device may be based on EPA emission factors, average emission factors derived from source tests of several similar devices, or emission factors derived from the source test of the individual device. Selection of the factor to be used is based on judgement of the applicability of each of the three factors to each source.

The methods employed to compute emission rates from operational and emission data is contained in Appendix A.

#### 4.0 DATA SOURCES

As a basic approach to conducting this program maximum use was made of data available as published information or contained in the files of public agencies and utilities, and of data obtained from industry.

By virtue of its broad and active area of responsibility and the advanced state of organization of its emissions inventory data, the Los Angeles County APCD was the prime source of data for the preliminary inventory. The LAC APCD has approximately 35,000 issued active permits and has processed information for most of these permit units into an electronic data processing (EDP) system. The EDP data file was obtained from the LAC APCD in tape form and was computer processed. The tape file contains the following data on each device.

- . Operating company name, plant address, location on a 1 mile grid.
- . Device category classification.
- . Operating hours each day of the week.
- . Pollutant emission rates (in lb/hr), including SOx.

The initial sort revealed that of the approximately 23,000 permit units recorded on the tape approximately 1,000 were recorded as being SOx emitters. In an attempt to keep the number of units inventoried as individual devices to a more manageable number, and yet account for at least 90% of the emissions, a cut off of 2 lb SOx/hr was employed. The sum of the emissions from the 235 LAC APCD devices emitting in excess of 2 lb SOx/hr was found to include 95% of all of the SOx emissions (on an hourly basis) of the LAC APCD EDP emission inventory, and hence was adopted as a pragmatic cutoff for this inventory. This maximum hourly rate of 2 lb/hr corresponds to full load emissions of SO<sub>2</sub> from oil burning devices rated at 10 million Btu/hr (MMB/h) burning 0.2% sulfur oil fuel. Hence this was adopted as equivalent basis for cutoff of the inventory. It should be noted that the 2 lb/hr cutoff on a year around operating device would correspond to about 9 tons SOx/year, or about a factor of 10 below the EPA inventory cutoff (Ref. 18). This cutoff point is consistent with the cutoff

point employed in the previous inventory of NOx emissions (Ref. 1) that included 1530 devices and served as the basis for the start of the SOx inventory.

Other valuable data obtained from the LAC APCD was daily fuel use (natural gas, refinery gas, and oil) by plant location for 10 electric utility stations (Ref. 21), 7 major refineries and 4 minor refineries (Ref. 12) for the period August 1972 through December 1974. In addition monthly fuel use was obtained from LAC APCD files for about 300 industrial, commercial and institutional plant sites.

Similar identification and device characteristics information was also obtained for many devices (larger than the cutoff) from the APCD's of Orange, Riverside, San Bernardino, Santa Barbara, and Ventura Counties. In addition a limited quantity of fuel use data was obtained, primarily for utilities and a few singularly large industrial sites. As in Los Angeles information was obtained only for devices on permit (and not necessarily all of these). Other devices of interest, not being on permit, could not be identified from APCD files.

Point source emissions compiled for the EPA were used for source identification, emissions comparison and material processing rates (Refs. 22,23). LAC APCD inventories were also reviewed (Refs. 24-29).

Other sources of emissions data reviewed during the program were the test data files of the Los Angeles, San Bernardino, and Orange County APCD's. Because of the broad extent of the LAC APCD source test data file, about 239 SOx tests of material processing plants since 1947, and because each record had to be screened by an APCD officer for trade secret data prior to making it available, only a limited sampling of test data was requested for this program. The 97 test reports requested for review were restricted to the latest test results from six categories of sources which were: 1964-74 refinery sulfur recovery unit tests, 1961-74 sulfuric acid plant tests, 1969-73 glass furnace

tests, 1968-74 fluidized bed catalytic cracking unit tests, 1969-71 petroleum coke kiln tests, 1962-74 metal furnace tests and 1972-73 gypsum and rockwool furnace tests. Data from these tests were either applied to applicable specific units in some cases, or were used to supplement and compare with data obtained during this program used to establish emission factors.

Finally, with respect to the determination of area distributed SOx sources, extensive use was made of demographic data obtained during the 1970 census. This information pertains primarily to gas fuel use that contributes only a minor amount of SOx. However as the data was available from the previous study of NOx, it was included for completeness.

During the preliminary inventory it became apparent that the single most significant contribution to the uncertainty in emissions from plants processing sulfur-bearing materials was the uncertainty in the material use patterns for these devices. Needed was data on hours per day, days per week these units were operated and the normal fraction of rated capacity. In order to obtain this data a five page questionnaire was sent out to approximately 38 plants in the Basin. Information was requested on each device within each plant that emits in excess of 2 lb/hr of SO<sub>2</sub>. In addition to device identification and rating information, requested was operational hours, material sulfur content and material use for August and December 1974 as well as total material use for 1974. Stack flow conditions and information on SOx emission control devices and projected material use for 1975, 1976, and 1980 were requested. Information gathered was used in compiling the final inventory. Questionnaire forms used are contained in Appendix E. However, tabulation of the questionnaire data is not provided in this report as most of the process-related data is considered as proprietary.

## 5.0 TEST PROGRAM

### 5.1 Objectives

The test program formulated for Phase II of the study had three main objectives:

1. Determine SOx emissions from major industrial devices that process sulfur-bearing materials in the South Coast Air Basin to resolve uncertainties in existing data.
2. Relate the SOx emissions to process rates so that emission factors can be developed for application to untested devices and improve the predictive capability for assessment of seasonal and capacity variations.
3. Obtain sufficient operational process data on the various devices to enable an assessment of potential emissions reduction by existing technology.

The objectives of the test program were formulated in terms of devices that process sulfur-bearing materials because these are the devices for which the largest uncertainty exists as discussed in Appendix C. The largest sources of SOx emission are the utility boilers. However, the SOx emissions arise only from the burning of fuel and can be properly accounted for from known fuel usage and sulfur content. Tests of these devices would not measurably improve the inventory.

The first objective had a dominant influence on the selection of the devices to be tested. While many of the major sources have been tested by local APCD agencies there is a wide degree of spread in the data among groups of common device types. The source of this spread was in most cases unknown and could only be resolved by further investigations of both stack emissions and process operation.

In regard to the second objective, the SOx emissions from devices that process sulfur-bearing materials are related to the sulfur content of materials processed. However, the relationship is not necessarily the more direct relation that exists for fuel burning devices. That is, the sulfur in materials is not necessarily all released and that which is released may not all be oxidized. Many such devices have bag houses or other particulate emission control units that indirectly influence SOx emissions or may have control units specifically for removal of SOx.

Achievement of the third objective was essential to the overall program objective of assessing the applicability of existing SOx reduction technology for further reduction of basin emissions. Significant reductions are being achieved by the oil refineries in control of SOx emissions from refinery fuel gas through the use of sulfur recovery plants and tail gas control units. Sufficient information on process operation must be made available to assess the application of these control techniques and others for development of cost-effective emissions control strategies for other devices.

## 5.2 Test Plan

The types of existing devices as used in the various industries are arranged in a matrix as shown in Table 5-I. The total number of inventoried devices is shown along with the number of devices for which tests were conducted.

The refinery fluid catalytic cracking units constitute the group with the largest emissions at the oil refineries. Tests on most of these units were conducted at the stack exit of the CO boilers. One of four Claus process sulfur recovery units operating without tail gas units was tested to obtain information on emissions prior to installation of tail gas units. Three of the 10 operating tail gas units were tested. Emissions from the tail gas units were found to be quite low and review with plant operators of all units conducted prior to the test program indicated that test of all units would be unproductive. Remaining industry devices include 9 identical oil field vapor phase reactors of which two were tested, one refinery odor abatement incinerator and one FCC unit thermal oxidizer handling excess flow not passed to the CO boiler.

Of five nearly identical petroleum coke kilns, two were tested. One kiln, although a large source, was unavailable for test because of construction in process to install emissions control equipment.



TABLE 5-1

SOUTH COAST BASIN SO<sub>x</sub> TEST MATRIX\*

		Number of Devices Tested/Total Basin Devices											
Industry	Devices	FCCU	Claus Plants* (no TGU)	Claus Plant* TGU	Sulfuric Acid Plants	Kilns	Furnaces	Coke Ovens	Coke Quench Towers	Sintering	Vapor Phase Reactors	Misc.	
Petroleum		6/8	1/4	3/10	0/1						2/9	2/2	14/34
Petroleum coke						2/5							2/5
Iron/Steel							4/5	1/7	0/3	2/2			7/17
Lead							3/10						3/10
Sulfuric Acid					3/4								3/4
Aggregate						0/7							0/7
Glass							6/25						6/25
Gypsum/Rockwool/ Cement						2/10							2/10
Misc. Industrial												1/1	
Total		6/8	1/4	3/10	3/5	4/22	13/40	1/7	0/3	2/2	2/9	3/3	38/113

\*Total of 20 Claus plants in Basin. Four have tail gas units (TGU) installed but not yet operating. Remaining 16 plants are serviced by 10 TGU. One Claus plant is inactive.

Tests in the iron and steel class involved primarily two plants. Furnace tests included one blast furnace, two open hearth furnaces and one iron melting cupola. One of the coke ovens was tested. Two sinter machines are the largest SOx sources and both were tested. Coke quench towers were determined to be inaccessible for proper test.

Tests were conducted on three devices at a lead processing plant. This included two cupola furnaces and one lead sweating furnace bank. Two additional cupola furnaces were reported to be unavailable for test because of emissions reduction equipment installation.

There are five sulfuric acid plants. Two units with different ratings were tested at one plant along with one unit at a second plant. A very large uncertainty, toward the high side, was found in the preliminary review (Appendix C) for these plants based on four sources of data and is believed related to the time period of emissions control unit installation. Test results indicated emissions were nearer the lower preliminary estimate of emissions.

Tests of one of the seven aggregate kilns were scheduled but not conducted at the request of the plant owner and because very recent APCD test results were available. The other six kilns are located in remote parts of the Basin and tests would not have been productive as adequate APCD tests were available and emissions are low.

Of the 25 basin glass furnaces, six were selected for test representing a range of emissions factors. Emissions vary widely based primarily on the amount of salt cake ( $\text{Na}_2\text{SO}_4$ ) or other sulfates used in the charge. Furnaces producing colored glass tend to have higher SOx emissions than those producing clear (flint) glass. The emissions from glass furnaces are a small percentage of the Basin total and tests of a larger number would have been unproductive.

Three gypsum calcining kettles, one rockwool furnace, six cement kilns, and many brakeshoe debonders constitute a group of devices with low emissions. One gypsum kettle was tested as was one of

the brakeshoe debonders. The rockwool furnace was scheduled to cease operation pending a new owner and was not operating during the test program. Tests were conducted on one cement kiln operating simultaneously on gas and coke.

For the most part, the types and sizes of devices that were intended for test, in accord with the priorities established in the preliminary inventory (Appendix C), were actually made available for test during this program. However, it was not possible to test every scheduled device, or to obtain all data on process conditions and operational variability, since the test program was conducted on the basis of voluntary consent of the operators.

It must be pointed out that the test program was intended primarily to verify an inventory based on extensive data obtained by EPA and local APCD's and to clarify emissions from sources where conflicts were apparent in data from more than one data source. In such a limited program it was not possible to get statistically significant quantities of test data.

Test methods employed and tabulations of the data are presented in Appendix D. Data correlation and application to the inventory are discussed for the various device types in Appendices G-M.

Briefly, the tests measurements were performed with continuous recording instruments for oxygen and sulfur dioxide. Strip chart recordings were made to allow assessment of the degree of process variability. Additional measurements of  $\text{SO}_2$  and  $\text{SO}_3$  were performed with a Shell-Emeryville wet chemistry impinger train (Ref. 30) and comparative data were obtained on selected sources with the use of the wet chemistry train specified by the LAC APCD (Ref. 31). In general, consistent agreement was obtained with all three methods of  $\text{SO}_2$  measurement. Measurement of  $\text{SO}_3$  showed some inconsistencies between the two wet chemistry methods as discussed in more detail in Appendix D.

Total emissions of SOx from the devices tested was found to be 90 tons/day as SO<sub>2</sub>. This compares with a total of 75 tons/day estimated for these same devices in the preliminary inventory. The higher level of emissions found in the test program was primarily the result of one refinery sulfur recovery plant operating without a tail gas unit where process variability results in a high uncertainty in emissions. The final inventory indicates total SOx emissions of 135 tons/day from all material processing devices. While only one-third of the material processing devices were tested, they represent about two-thirds of the total emissions from material processing plants.

## 6.0 INVENTORY OF SO<sub>x</sub> EMISSIONS IN THE SOUTH COAST AIR BASIN FOR 1974

The results of the Basin inventory of SO<sub>x</sub> emissions, the summaries of emissions from stationary sources for 1974, are presented in this section. Point source emissions have been recorded in computerized format as discussed in Appendix B. Point source devices have been classified by (1) type of application, (2) type of device and (3) geographic location. Emissions are given for total SO<sub>x</sub> and for SO<sub>3</sub>. Computer sorting according to these classifications has formed the basis for the inventory reported in this section.

The inventory is based largely on the recent inventory of NO<sub>x</sub> (Ref.1) conducted for the ARB with the addition of SO<sub>x</sub> sources not emitting NO<sub>x</sub>. The inventory period for the NO<sub>x</sub> program was the fiscal year of July 1972 through June 1973. Much information on device operating capacity and fuel use gathered for that survey has been retained for the current SO<sub>x</sub> inventory. However as discussed in Section 3.0, the final results of the current program are based on the calendar year 1974 and updating of the most significant sources to this period was performed for the inventory of SO<sub>x</sub> emissions presented here.

As indicated in Section 3.0, emissions have been inventoried on the basis of a summer (August) and a winter (December) average daily value and also an annual average daily value. The inventory is also presented for the six separate counties and for the total Basin to facilitate comparison with other inventories. Such comparisons should, however, be made with caution. Every inventory is subject to particular uncertainties that render direct agreement on a tonnage basis virtually impossible. Even if all sources were inventoried from a detailed source test of each device, there would be variations over a given year in the operation of each device that could only be resolved with continuous monitoring on a day-to-day basis. The purpose of an inventory is to identify the significant sources and estimate in as practical a manner possible the magnitude of emissions. It is invalid to attempt a critical comparison of the total emissions from two separate inventories without a similar critical comparison of the detailed point source estimates from which each inventory was compiled.

## 6.1 Inventory by Device Type for the Basin

The 1974 inventory of stationary SOx points sources sorted by device type is given in Table 6-I for the total Basin. The most significant result is the difference in the summer and winter total SOx emissions of 305 and 465 tons as SO<sub>2</sub>/day respectively. This difference is significant not because the summer value is the lower of the two but because the summer value, when viewed in respect to previous years, is in the process of a substantial increase. This difference is attributable primarily to the fuel burning sources; boilers for which in previous years gas was the main summer fuel and oil the main winter fuel. For other devices where processed material is the primary source of SOx and summer and winter differences are much less apparent.

In the summer months utility boilers emit 43% of the SOx, furnaces and kilns contribute 22% of the SOx, with coke kilns and metal furnaces predominating. Petroleum fluid catalytic cracking, contributing 16%, and sulfur recovery plants, emitting 11% are also large sources of emissions in the summer.

In the winter 57% of the SOx is emitted by utility boilers. Winter emissions from furnaces and kilns, nearly the same as in the summer on an absolute basis, are only 13% of the total winter emissions. Petroleum fluid catalytic cracking units emit 11% and sulfur recovery units 7% of the winter SOx emissions. The remaining device groups are individually less than 3% of the winter emissions and together total 5%.

For emissions expressed on an annual basis, utility boilers are again the dominant source (50%). Furnaces and kilns contribute 19% and petroleum catalytic cracking 13%. The sulfur recovery units emit 9% and the remaining device groups individually are less than 2% and together total 5% of the annual emissions.

The emissions in Table 6-I are for total sulfur oxides that include sulfur dioxide (SO<sub>2</sub>) and sulfur trioxide (SO<sub>3</sub>). Emissions of SO<sub>3</sub> alone have also been estimated for each source and, in 1974, 13 tons of SO<sub>3</sub>/day were emitted on an annual average daily basis. As shown in

TABLE 6-I

TOTAL SOx INVENTORY BY DEVICE TYPE  
FOR SOUTH COAST BASIN

Device	Number	(2) Daily SOx Emissions, Tons SOx as SO <sub>2</sub> /Day		
		August	December	Annual
I. BOILERS	680	143.31	297.71	183.37
A. Utility	70	131.21	267.26	171.76
B. Industrial-Refinery	78	1.01	5.97	3.05
C. Industrial-Other	286	11.09	16.42	8.19
D. Coml/Inst.	246	0.00	8.06	0.37
II. FURNACES, KILNS	275	66.75	60.41	66.30
A. Coke/Carbon	5	27.68	26.40	25.52
B. Primary Metals	67	29.95	22.94	31.25
C. Aggregate	7	1.25	1.40	1.41
D. Secondary Metals	73	4.92	5.29	5.57
E. Cement	10	0.52	0.55	0.36
F. Glass	26	2.41	2.19	2.15
G. Other	87	0.02	1.64	0.04
III. PETROLEUM CRACKING				
A. Fluid Catalytic	8	50.10	51.78	45.56
IV. SULFUR RECOVERY				
A. Claus Units	19	32.74	31.86	30.66
V. PROCESS HEATERS				
A. Petroleum	335	2.33	13.03	7.15
VI. OIL FIELD RECOVERY				
A. Vapor Phase Reactors	9	5.40	5.40	5.41
VII. SULFURIC ACID				
A. Contact Units	5	3.09	2.76	2.65
VIII. INTERNAL COMB. ENGINES	144	0.42	0.85	0.39
A. Gas Turbine	46	0.42	0.85	0.39
B. Reciprocating	98(1)	0.00	0.00	0.00
IX. MISCELLANEOUS	108	0.52	1.33	0.65
TOTAL	1583	304.66	465.13	342.14

(1) Represents groupings of 488 engines by location.

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(2) Numbers presented represent computer summations and should be considered significant only to two digits.

Table 6-II, utility boilers are the major source of  $\text{SO}_3$  emitting 41%, 56%, and 49% of the summer, winter and annual rates, respectively. Kilns for calcining petroleum coke and refinery fluid catalytic cracking units are also major sources, contributing 32% of the annual emissions of  $\text{SO}_3$ . Sulfur recovery and sulfuric acid plants, because of the low exhaust temperatures, were considered to be possible high sources of  $\text{SO}_3$  when the current program began. However, tests of these units showed very low emissions -- in some cases, below the detectable limit -- as the result the emissions control units now in operation. These control units consist either of tailgas chemical processes that remove sulfur or acid mist eliminators.

Each of the tabulated device categories is discussed more fully below.

Boilers - Utility - Of the 70 utility boilers, 91% of the annual utility boiler  $\text{SO}_x$  emissions are emitted by 34 boilers with rated heat inputs of 1500 MMB/h to 7125 MMB/h. About 78% is emitted by 24 boilers rated in excess of 1775 MMB/h, the current level of regulations in Los Angeles County for  $\text{NO}_x$  emissions. These same boilers emit 68% of the winter  $\text{NO}_x$  emissions (Ref. 1) compared with 72% of the winter  $\text{SO}_x$  emissions. There is currently no distinction in the  $\text{SO}_x$  regulations regarding size of unit and all units are required to burn oil at no more than 0.5% sulfur. Boilers rated at less than 1500 MMB/h currently are emitting about 15 tons of  $\text{SO}_x$ /day.

$\text{SO}_x$  emissions for utility boilers were determined from total station monthly fuel useage and individual unit capacity factors were not obtained for 1974 as they were for the 72/73 inventory of  $\text{NO}_x$ . It was then not possible to determine if particular units were out of service at any time in 1974 and if so what impact this would have on future emissions. Since  $\text{SO}_x$  is directly related to fuel use and sulfur content, and projections for total utility fuel use were available, the effect of individual unit contributions are not significant as in the



TABLE 6-II

$\text{SO}_3$  INVENTORY BY DEVICE TYPE <sup>(1)</sup>  
FOR SOUTH COAST BASIN

Device	Number	(3) Daily $\text{SO}_3$ Emissions, Tons $\text{SO}_3$ as $\text{SO}_3$ /Day		
		August	December	Annual
I. BOILERS	680	5.38	11.14	6.87
A. Utility	70	4.93	10.02	6.44
B. Industrial-Refinery	78	0.03	0.22	0.11
C. Industrial-Other	286	0.42	0.59	0.31
D. Coml/Inst.	246	0.00	0.31	0.01
II. FURNACES, KILNS	275	4.44	4.14	4.22
A. Coke/Carbon	5	2.94	2.80	2.70
B. Primary Metals	67	0.93	0.71	0.96
C. Aggregate	7	0.04	0.05	0.05
D. Secondary Metals	73	0.14	0.15	0.17
E. Cement	10	0.08	0.08	0.04
F. Glass	26	0.31	0.28	0.29
G. Other	87	0.00	0.07	0.01
III. PETROLEUM CRACKING	8	1.75	1.81	1.59
A. Fluid Catalytic				
IV. SULFUR RECOVERY				
A. Claus Units	19	0.23	0.13	0.15
V. PROCESS HEATERS				
A. Petroleum	335	0.06	0.47	0.26
VI. OIL FIELD RECOVERY				
A. Vapor Phase Reactors	9	0.12	0.12	0.12
VII. SULFURIC ACID				
A. Contact Units	5	0.03	0.03	0.03
VIII. INTERNAL COMB. ENGINES	144	0.01	0.03	0.01
A. Gas Turbine	46	0.01	0.03	0.01
B. Reciprocating	98 (2)	0.00	0.00	0.00
IX. MISCELLANEOUS	108	0.03	0.04	0.03
TOTAL	1583	12.05	17.91	13.28

(1) Emissions based on  $\text{SO}_3$  molecular weight of 80 for  $\text{SO}_3$   
Emissions as equivalent  $\text{SO}_2$  = Table value X  $\frac{64}{80}$

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Emissions as equivalent sulfuric acid ( $\text{H}_2\text{SO}_4 \cdot 2\text{H}_2\text{O}$ ) = Table value X  $\frac{134}{80}$

(2) Represents groupings of 488 engines by location.

(3) Numbers presented represent computer summations and should be considered significant only to two digits.

case of NOx emissions that are load, size, and design dependent. Summer and winter emissions reflect actual 1974 fuel use rather than assuming all gas in the summer and all oil in the winter to better reflect 1974 conditions.

Boilers - Industrial - This category of boilers includes 364 units rated from 350 MMB/h down to the cut-off of 10 MMB/h. Boilers burning natural gas only (61) contribute negligible emissions. Boilers burning residual oil (79) contribute 26% of the annual boiler SOx and 35% of the winter SOx emissions. A large number of boilers (210), operating on natural gas or distillate oil, contribute 45% of the winter SOx emissions but only 6% of the annual values. The 14 remaining boilers operate exclusively on process gas and contribute 68% annual SOx.

Eight large CO boilers operating in refineries are not included in this category as they were in the NOx program (Ref. 1). This is because the SOx emitted comes primarily from the fluid catalytic cracking units (FCCU) for which the CO boilers serve to incinerate CO and sulfur to CO<sub>2</sub> and SO<sub>2</sub>/SO<sub>3</sub>. All emissions from the CO boiler stacks are inventoried under FCCU emissions including fuels burned directly in the CO boilers that contribute an estimated 0.6 tons of SOx/day of the total 46 tons/day inventoried for the FCC units.

The inventory of boilers with respect to SOx emissions is expected to be fairly complete as all oil burning units are required to be on permit. Many other boilers are believed to be unidentified but burn only natural gas so emissions are low. This picture could change significantly as many boilers are converted to burn oil in the face of increased gas curtailment.

Of the industrial boilers, 78 are located in oil refineries. Of these, 5 operate only on refinery gas, 2 only on natural gas, 21 on distillate oil or gas, and 50 on residual oil or gas. Emissions from these boilers are 27% of the total industrial boiler category. Inventory of these refinery devices was based on refinery fuel reports to the LA APCD and the method of apportioning fuel used in boilers is discussed in Appendix G.

Boilers - Commercial/Institutional - The 246 units in the inventory were responsible for only 0.37 tons of SOx/day or 0.2% of the boiler emissions on an annual basis. During the winter increased oil use raises emissions to 8 tons/day or 3% of total boiler emissions. Fuel useage for these boilers was based primarily on 72/73 data. Summer emissions are based on all gas operation while winter emissions are based on full oil operation, as no specific fuel use patterns were available. Increased oil use by these units will increase the annual average approaching the winter level of 8 tons/day with complete gas curtailment.

Furnace/Kilns - This category includes petroleum coke calcining kilns, iron ore sintering plants, steel furnaces, lead furnaces, aggregate calcining kilns, glass furnaces, and cement kilns. Of the inventoried emissions of 66 tons SOx/day, 39% is emitted by the 5 Basin petroleum coke kilns. While these kilns emit only 8% of the total Basin SOx, they emit 20% of the SO<sub>3</sub> (Table 6-II). This is the result of very high stack temperatures up to 2000°F resulting in high conversion of sulfur driven off the coke from SO<sub>2</sub> to SO<sub>3</sub> as discussed in Section 2.1. Two iron ore sintering plants in the metals industry emit 4.4 tons of SOx/day. Seven coke ovens in a steel mill are also large sources emitting 7 tons/day. Burning of coke oven gas in other steel mill furnaces results in emissions of 13 tons/day. An additional 7 tons/day is emitted from blast and open hearth steel furnaces where fuel burning is the source of SOx.

Lead furnaces (4) are responsible for emissions of 5.3 tons of SOx/day from sulfur released from both fuel and coke added to scrap.

The remaining 4 tons/day are emitted from aggregate kilns (1.4 T/d), glass furnaces (2.2 T/d) and cement kilns (.4 T/d) as the result of sulfur release from materials processed and fuel burned.

Petroleum Cracking - Fluid Catalytic - Eight large units in the Basin refineries emit 46 tons/day of SOx or 14% of Basin annual SOx emissions. Emissions exit from CO boiler stacks but are generated by burning of coke from the catalyst in the FCC regenerator. Summer and winter emissions of 50 and 52 tons/day are higher than the annual average

because the annual value reflects some operation at reduce capacity and shutdowns. The actual hourly emission rates when these units are all running at near full capacity are about 55-60 tons/day and these are the values that are frequently inventoried for these units. In actuality, inventorying the FCC unit is very difficult as SOx emissions are a very complex function of crude feed properties, crude processing prior to the FCC, and FCC operating conditions. These are discussed in more (but limited) detail in Appendix H.

Sulfur Recovery - Claus Units - There are 19 active Claus process units in the Basin, recovering sulfur from refinery waste gas and currently emitting 31 tons of SOx/day. However, 96% of this is emitted by only 4 units. Twelve tailgas control units are servicing the nineteen plants and for plants where these units are properly operating, the emissions are 403 tons/year (1.1 tons/day). These tailgas units were installed in compliance with LA County Rule 53.2 limiting SOx to 500 ppm. At this concentration level the allowable total emissions would be 13 tons/day. However, the tailgas units reduce emissions well below the 500 ppm level with concentrations measured in this program ranging from 5 to 115 ppm. Tailgas processes employed include SCOT, Wellman-Lord, and Beavon processes and are discussed in Appendix I. One of the sulfur plants actually has no inventoried emissions as sulfur plant exhaust is ducted to the FCC stack and FCC feed is desulfurized in lieu of a sulfur plant tailgas unit.

Three units that emit a total 30 tons/day were on variance from Rule 53.2 as tailgas units installed did not operate properly. Completely new units of a different process are nearing completion and are projected to reduce emissions to about 1.3 tons/day that would result in total sulfur plant emissions of about 3 tons/day in 1976.

Emissions from an uncontrolled Claus plant are highly variable, dependent on  $H_2S/SO_2$  volume ratio. Optimum sulfur extraction occurs at an  $H_2S/SO_2$  volume ratio of 2 entering the convertor. Plant controls that do not maintain this ratio can result in large emission increases in units with no tailgas system. Tailgas units not only reduce emissions

but also the sensitivity of emissions to control. While tests conducted in this program, and subsequent use of the data in the inventory, showed very low emissions, the effect of plant operational controls adds an uncertainty on the high side to inventoried emissions as discussed more fully in Appendix I.

The emissions from these sulfur plants must be viewed in the light that the Claus plants themselves are in fact sulfur oxides emission control units. At full capacity these units (neglecting standby back-up units) are capable of recovering 1250 tons of sulfur per day that would be converted to 2500 tons of SO<sub>x</sub>/day if the waste gases were incinerated. The sulfur recovered in these plants is a saleable product at a current price that probably makes these plants economical.

Process Heaters - Petroleum - Of 335 process heaters, all used in oil refineries, 128 operate on natural or refinery gas fuels and 207 on the same gases or oil. Heat inputs range from 10 to 450 MMB/h providing heat to refinery crude or fractions of crude in the various refining processes. SO<sub>x</sub> emissions occur from burning refinery gas and oil. The basis for inventory of emissions for these heaters was the refinery fuel use reported to the LA APCD and methods for apportioning of fuels to the various heaters is discussed in Appendix G.

Total emissions from these heaters is 7.15 tons of SO<sub>x</sub>/day, annual average basis. Summer and winter emissions are 2.33 and 13.03 tons/day, respectively, reflecting increased oil use in the winter. These emissions contribute only 2% to the annual Basin emissions.

Oil Field Recovery - Vapor Phase Reactors - Nine of the devices were inventoried. However, one device has been removed from the facility and identified as out of service in the SO<sub>x</sub> NEDS format computer data base. Two other units were not operated in 1974 and emissions are based on only 6 units operating. These devices, all located at one oil field in Orange County, incinerate H<sub>2</sub>S to SO<sub>2</sub>.

The  $H_2S$  is generated by air forced underground where burning takes place to increase oil yield. Exhaust from this process is distributed equally to the operating units. Based on source tests conducted and relatively constant levels of  $H_2S$ , the emissions are inventoried at 5.4 tons of  $SO_x$ /day, contributing only 2% of Basin emissions, but 27% of the  $SO_x$  emissions in Orange County. (Emissions by county are discussed below).

Sulfuric Acid - Contact Units - Five contact process sulfuric acid manufacturing plants are operated in the Basin. These units, together with sulfur recovery plants, primarily process the acid gas by product from the sulfur stripping operations in oil refineries. These units are therefore located close to refineries and one unit is in a refinery. Some units are independent of refinery offgas and burn sulfur directly to meet acid production requirements. Emissions are relatively constant through the year, tending to follow refinery processing rates. Emissions from these plants are about 3 tons/day, having been recently reduced from over 16 tons/day to meet LA county Rule 53.2 by a combination of control techniques as discussed in Appendix J. As with sulfur plants, emissions from acid plants can be operation control dependent.

Internal Combustion Engines - Gas turbines (46 sets) and reciprocating engines (98 sets) are negligible sources of Basin  $SO_x$  emissions contributing only 0.39 tons of  $SO_x$ /day. Gas turbines are low as they are used primarily for peaking operations and operate on low sulfur distillate oil. However, the rated heat input rate for the 34 industrial and utility stationary gas turbines is 8956 MMB/hr. All of these units operating simultaneously at full capacity and burning 0.2% S oil could emit 1800 lb of  $SO_x$ /hr or 22 tons/day. As these units may be increasingly used to meet power growth demands, their potential for substantial emissions should not be ignored.

Miscellaneous - This category includes a large number (108) of devices in the petroleum, food and chemical industries that have heat inputs of 10 MMB/h or greater but operate primarily on natural gas

and together total less than 1 ton of SOx/day. As with other gas-fired devices, increased curtailments will undoubtedly force increased oil use. Complete replacement of natural gas with 0.5% S oil would increase emissions to about 16 tons/day. Most units, however, would probably use only distillate oils and increases in emissions would fall between the 1 to 16 ton/day levels.

In 1974, SOx emissions occurred primarily from fuel burning in utility boilers and from materials processed, that is from a relatively few large devices. However, there are a large number of smaller devices that have previously burned only natural gas or small quantities of oil. These many sources pose a potential problem for increased SOx emissions that is critical in light of their much wider Basin dispersion and lower stacks that tend to result in more immediate ground level concentration increases in more highly populated areas. This would lend greater support to control strategies that emphasize to a greater extent, restoration of natural gas as an alternative to more stringent regulations on the larger sources.

## 6.2 Inventory by County for Device Types

Los Angeles County contributes 68% of the annual Basin SOx emissions and 73% of annual Basin SO<sub>3</sub> emissions. Distributions for summer, winter, and annual SOx emissions in LA and other counties is summarized in Table 6-III.

Also shown are the respective APCD values for total SOx emissions in each county based on APCD inventories for recent years. These values are given for reference only and no specific conclusions can be or should be drawn in comparison of the APCD values with the current inventory county values or of the total of the APCD values as the values are for different years and reflect various methods and sources. Any apparent differences are insignificant compared with seasonal fluctuations and future SOx growth as discussed in Sections 6.5 and 7.0, respectively.

More detailed distributions from the current inventory by device categories in each county are given in Tables 6-IV, 6-V, and 6-VI for total SOx and in Tables 6-VII, 6-VIII and 6-IX for SO<sub>3</sub>, each set of three tables showing summer, winter and annual emissions, respectively.

These tables show that emissions are highest in Los Angeles County and occur primarily from utility boilers, coke kilns, petroleum catalytic cracking and sulfur plants. San Bernardino County has the second highest annual emission rate coming mainly from utility boilers and one large primary steel mill. Ventura County is third highest, annually, second in the summer and emissions are almost entirely from utility boilers at two stations. In Orange County, with 6% of Basin SOx, emissions occur from utility boilers at one station, an aggregate kiln, and oil field H<sub>2</sub>S incineration reactors. Riverside and Santa Barbara Counties both contribute less than 0.1%.



TABLE 6-III

SO<sub>x</sub> INVENTORY BY COUNTY FOR 1974  
 FOR STATIONARY SOURCES IN THE  
 SOUTH COAST AIR BASIN

County	Percent of Basin SO <sub>x</sub>			Current Inventory Annual Tons/Day	APCD, Annual Tons/Day	Year of APCD Value
	Summer	Winter	Annual			
Los Angeles	62.4	71.7	68.2	233.28	230.0 <sup>(32)</sup>	1974
San Bernardino	18.4	12.1	16.5	56.38	60.9 <sup>(33)</sup>	1973
Ventura	13.2	8.6	9.4	32.21	20.6 <sup>(34)</sup>	1972
Orange	6.0	7.3	5.8	20.01	27.0 <sup>(35)</sup>	1972
Riverside	0.0	0.2	0.1	0.25	2.1 <sup>(36)*</sup>	1971
Santa Barbara	0.0	0.0	0.0	0.01	0.5 <sup>(37)*</sup>	1970
Basin Total Tons SO <sub>x</sub> as SO <sub>2</sub> /Day	304.66	465.13	342.14	<u>342.14</u>	<u>341.1</u>	

\*Total County

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TABLE 6-IV

TOTAL SO<sub>x</sub> INVENTORY BY DEVICE TYPE AND COUNTY  
SUMMER AVERAGE DAILY SO<sub>x</sub> EMISSIONS, TONS/DAY AS SO<sub>2</sub>

Device	L.A.	Orange	Rivers.	San Bern.	San. Barb.	Ventura	Basin
I. BOILERS							
A. Utility	67.76	11.40	--	12.21	--	39.84	131.21
B. Industrial-Refinery	1.01	--	--	--	--	0.00	1.01
C. Industrial-Other	0.01	0.00	0.00	11.08	--	0.00	11.09
D. Coml/Inst.	0.00	0.00	0.00	0.00	--	0.00	0.00
II. FURNACES, KILNS							
A. Coke/Carbon	27.68	--	--	--	--	--	27.68
B. Primary Metals	2.58	--	--	27.37	--	--	29.95
C. Aggregate	--	0.86	--	--	--	0.39	1.25
D. Secondary Metals	0.18	0.00	0.00	4.74	--	0.00	4.92
E. Cement	--	--	0.00	0.52	--	--	0.52
F. Glass	1.81	0.60	0.00	--	--	--	2.41
G. Other	0.01	--	0.00	0.00	0.00	0.01	0.02
III. PETROLEUM CRACKING							
A. Fluid Catalytic	50.10	--	--	--	--	--	50.10
IV. SULFUR RECOVERY							
A. Claus Units	32.74	--	--	--	--	--	32.74
V. PROCESS HEATERS							
A. Petroleum	2.33	--	--	--	--	--	2.33
VI. OIL FIELD RECOVERY							
A. Vapor Phase Reactors	--	5.40	--	--	--	--	5.40
VII. SULFURIC ACID							
A. Contact Units	3.09	--	--	--	--	--	3.09
VIII. INTERNAL COMB. ENGINES							
A. Gas Turbine	0.38	0.00	--	0.03	--	0.01	0.42
B. Reciprocating	0.00	0.00	--	0.00	0.00	0.00	0.00
IX. MISCELLANEOUS	0.52	0.00	0.00	0.00	--	0.00	0.52
TOTAL	190.20	18.26	0.00	55.95	0.00	40.25	304.66

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-- Sources not present

0.00 Sources present, less than 0.01 tons/day

Numbers presented in this and following tables are significant only to two digits.

TABLE 6-V

TOTAL SO<sub>x</sub> INVENTORY BY DEVICE TYPE AND COUNTY  
WINTER AVERAGE DAILY SO<sub>x</sub> EMISSIONS, TONS/DAY AS SO<sub>2</sub>

Device	L.A.	Orange	Rivers.	San Bern.	San. Barb.	Ventura	Basin
I. BOILERS							
A. Utility	175.15	24.63	--	28.52	--	38.96	267.26
B. Industrial-Refinery	5.97	--	--	--	--	0.00	5.97
C. Industrial-Other	10.04	1.21	0.38	4.71	--	0.08	16.42
D. Coml/Inst.	6.06	0.79	0.25	0.75	--	0.21	8.06
II. FURNACES, KILNS							
A. Coke/Carbon	26.40	--	--	--	--	--	26.40
B. Primary Metals	6.71	--	--	16.23	--	--	22.94
C. Aggregate	--	0.86	--	--	--	0.54	1.40
D. Secondary Metals	0.53	0.00	0.07	4.69	--	0.00	5.29
E. Cement	--	--	0.00	0.55	--	--	0.55
F. Glass	1.64	0.50	0.05	--	--	--	2.19
G. Other	0.54	--	0.19	0.72	0.17	0.02	1.64
III. PETROLEUM CRACKING							
A. Fluid Catalytic	51.78	--	--	--	--	--	51.78
IV. SULFUR RECOVERY							
A. Claus Units	31.86	--	--	--	--	--	31.86
V. PROCESS HEATERS							
A. Petroleum	13.03	--	--	--	--	--	13.03
VI. OIL FIELD RECOVERY							
A. Vapor Phase Reactors	--	5.40	--	--	--	--	5.40
VII. SULFURIC ACID							
A. Contact Units	2.76	--	--	--	--	--	2.76
VIII. INTERNAL COMB. ENGINES							
A. Gas Turbine	0.37	0.45	--	0.03	--	0.00	0.85
B. Reciprocating	0.00	0.00	--	0.00	0.00	0.00	0.00
IX. MISCELLANEOUS	0.88	0.31	0.00	0.12	--	0.02	1.33
TOTAL	333.72	34.15	0.94	56.32	0.17	39.83	465.13

-- Sources not present

0.00 Sources present, less than 0.01 tons/day

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TABLE 6-VI

TOTAL SO<sub>x</sub> INVENTORY BY DEVICE TYPE AND COUNTY  
ANNUAL AVERAGE DAILY SO<sub>x</sub> EMISSIONS, TONS/DAY AS SO<sub>2</sub>

Device	L.A.	Orange	Rivers.	San Bern.	San. Barb.	Ventura	Basin
I. BOILERS							
A. Utility	109.83	12.92	--	17.30	--	31.71	171.76
B. Industrial-Refinery	3.03	--	--	--	--	0.02	3.05
C. Industrial-Other	0.42	0.07	0.03	7.67	--	0.00	8.19
D. Coml/Inst.	0.31	0.02	0.01	0.03	--	0.00	0.37
II. FURNACES, KILNS							
A. Coke/Carbon	25.52	--	--	--	--	--	25.52
B. Primary Metals	5.46	--	0.00	25.79	--	--	31.25
C. Aggregate	--	0.98	--	--	--	0.43	1.41
D. Secondary Metals	0.18	--	0.00	5.39	--	0.00	5.57
E. Cement	--	--	0.21	0.15	--	--	0.36
F. Glass	1.61	0.54	0.00	--	--	--	2.15
G. Other	0.01	--	0.00	0.01	0.01	0.01	0.04
III. PETROLEUM CRACKING							
A. Fluid Catalytic	45.56	--	--	--	--	--	45.56
IV. SULFUR RECOVERY							
A. Claus Units	30.66	--	--	--	--	--	30.66
V. PROCESS HEATERS							
A. Petroleum	7.15	--	--	--	--	--	7.15
VI. OIL FIELD RECOVERY							
A. Vapor Phase Reactors	--	5.41	--	--	--	--	5.41
VII. SULFURIC ACID							
A. Contact Units	2.65	--	--	--	--	--	2.65
VIII. INTERNAL COMB. ENGINES							
A. Gas Turbine	0.27	0.05	--	0.03	--	0.04	0.39
B. Reciprocating	0.00	0.00	--	0.00	0.00	0.00	0.00
IX. MISCELLANEOUS	0.62	0.02	0.00	0.01	--	0.00	0.65
TOTAL	233.28	20.01	0.25	56.38	0.01	32.21	342.14

-- Sources not present

0.00 Sources present, less than 0.01 tons/day

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TABLE 6-VII

SO<sub>3</sub> INVENTORY BY DEVICE TYPE AND COUNTY  
SUMMER AVERAGE DAILY SO<sub>3</sub> EMISSIONS, TONS/DAY AS SO<sub>3</sub>

Device	L.A.	Orange	Rivers.	San Bern.	San. Barb.	Ventura	Basin
I. BOILERS							
A. Utility	2.54	0.43	--	0.46	--	1.50	4.93
B. Industrial-Refinery	0.03	--	--	--	--	0.00	0.03
C. Industrial-Other	0.00	0.00	0.00	0.42	--	0.00	0.42
D. Coml/Inst.	0.00	0.00	0.00	0.00	--	0.00	0.00
II. FURNACES, KILNS							
A. Coke/Carbon	2.94	--	--	--	--	--	2.94
B. Primary Metals	0.11	--	0.00	0.82	--	--	0.93
C. Aggregate	--	0.03	--	--	--	0.01	0.04
D. Secondary Metals	0.01	--	0.00	0.13	--	--	0.14
E. Cement	--	--	0.00	0.08	--	--	0.08
F. Glass	0.28	0.03	0.00	--	--	--	0.31
G. Other	0.00	--	0.00	0.00	0.00	0.00	0.00
III. PETROLEUM CRACKING							
A. Fluid Catalytic	1.75	--	--	--	--	--	1.75
IV. SULFUR RECOVERY							
A. Claus Units	0.23	--	--	--	--	--	0.23
V. PROCESS HEATERS							
A. Petroleum	0.06	--	--	--	--	--	0.06
VI. OIL FIELD RECOVERY							
A. Vapor Phase Reactors	--	0.12	--	--	--	--	0.12
VII. SULFURIC ACID							
A. Contact Units	0.03	--	--	--	--	--	0.03
VIII. INTERNAL COMB. ENGINES							
A. Gas Turbine	0.01	0.00	--	0.00	--	0.00	0.01
B. Reciprocating	0.00	0.00	--	0.00	0.00	0.00	0.00
IX. MISCELLANEOUS	0.03	0.00	0.00	0.00	--	0.00	0.03
TOTAL	8.02	0.61	0.00	1.91	0.00	1.51	12.05

-- Sources not present

0.00 Sources present, less than 0.01 tons/day

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TABLE 6-VIII

SO<sub>3</sub> INVENTORY BY DEVICE TYPE AND COUNTY  
WINTER AVERAGE DAILY SO<sub>3</sub> EMISSIONS, TONS/DAY AS SO<sub>3</sub>

Device	L.A.	Orange	Rivers.	San Bern.	San. Barb.	Ventura	Basin
I. BOILERS							
A. Utility	6.57	0.92	--	1.07	--	1.46	10.02
B. Industrial-Refinery	0.22	--	--	--	--	0.00	0.22
C. Industrial-Other	0.36	0.04	0.01	0.18	--	0.00	0.59
D. Coml/Inst.	0.23	0.03	0.01	0.03	--	0.01	0.31
II. FURNACES, KILNS							
A. Coke/Carbon	2.80	--	--	--	--	--	2.80
B. Primary Metals	0.27	--	0.00	0.44	--	--	0.71
C. Aggregate	--	0.03	--	--	--	0.02	0.05
D. Secondary Metals	0.02	--	0.00	0.13	--	--	0.15
E. Cement	--	--	0.00	0.08	--	--	0.08
F. Glass	0.26	0.02	0.00	--	--	--	0.28
G. Other	0.03	--	0.01	0.03	0.00	0.00	0.07
III. PETROLEUM CRACKING							
A. Fluid Catalytic	1.81	--	--	--	--	--	1.81
IV. SULFUR RECOVERY							
A. Claus Units	0.13	--	--	--	--	--	0.13
V. PROCESS HEATERS							
A. Petroleum	0.47	--	--	--	--	--	0.47
VI. OIL FIELD RECOVERY							
A. Vapor Phase Reactors	--	0.12	--	--	--	--	0.12
VII. SULFURIC ACID							
A. Contact Units	0.03	--	--	--	--	--	0.03
VIII. INTERNAL COMB. ENGINES							
A. Gas Turbine	0.01	0.02	--	0.00	--	0.00	0.03
B. Reciprocating	0.00	0.00	--	0.00	0.00	0.00	0.00
IX. MISCELLANEOUS	0.03	0.01	0.00	0.00	--	0.00	0.04
TOTAL	13.24	1.19	0.03	1.96	0.00	1.49	17.91

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-- Sources not present

0.00 Sources present, less than 0.01 tons/day

TABLE 6-IX

SO<sub>3</sub> INVENTORY BY DEVICE TYPE AND COUNTY  
ANNUAL AVERAGE DAILY SO<sub>3</sub> EMISSIONS, TONS/DAY AS SO<sub>3</sub>

Device	L.A.	Orange	Rivers.	San Bern.	San. Barb.	Ventura	Basin
I. BOILERS							
A. Utility	4.12	0.48	--	0.65	--	1.19	6.44
B. Industrial-Refinery	0.11	--	--	--	--	0.00	0.11
C. Industrial-Other	0.02	--	0.00	0.29	--	0.00	0.31
D. Coml/Inst.	0.01	--	0.00	0.00	--	0.00	0.01
II. FURNACES, KILNS							
A. Coke/Carbon	2.70	--	--	--	--	--	2.70
B. Primary Metals	0.23	--	0.00	0.73	--	--	0.96
C. Aggregate	--	0.03	--	--	--	0.02	0.05
D. Secondary Metals	0.01	--	0.00	0.16	--	--	0.17
E. Cement	--	--	0.02	0.02	--	--	0.04
F. Glass	0.26	0.03	0.00	--	--	--	0.29
G. Other	0.00	--	0.01	0.00	0.00	0.00	0.01
III. PETROLEUM CRACKING							
A. Fluid Catalytic	1.59	--	--	--	--	--	1.59
IV. SULFUR RECOVERY							
A. Claus Units	0.15	--	--	--	--	--	0.15
V. PROCESS HEATERS							
A. Petroleum	0.26	--	--	--	--	--	0.26
VI. OIL FIELD RECOVERY							
A. Vapor Phase Reactors	--	0.12	--	--	--	--	0.12
VII. SULFURIC ACID							
A. Contact Units	0.03	--	--	--	--	--	0.03
VIII. INTERNAL COMB. ENGINES							
A. Gas Turbine	0.01	0.00	--	0.00	--	0.00	0.01
B. Reciprocating	0.00	0.00	--	0.00	0.00	0.00	0.00
IX. MISCELLANEOUS	0.03	0.00	0.00	0.00	--	0.00	0.03
TOTAL	9.53	0.66	0.03	1.85	0.00	1.21	13.28

-- Sources not present

0.00 Sources present, less than 0.01 tons/day

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### 6.3 Inventory by Application

This grouping of the inventory is to summarize emissions by application category in order to indicate what types of activities are responsible for what fractions of the total stationary source emissions. This breakdown is shown in terms of winter average daily SOx emissions in Table 6-X with values given for each county and the Basin. Winter values are presented to emphasize those sources where increased oil use in the future will result in both summer and annual emissions rising to nearly equal winter levels. Each application category is briefly discussed below.

Utilities - The electric utilities contributed the dominant fraction of total stationary source winter emissions of SOx, in 1974 about 58% or 268 tons/day. Nearly all is from steam boilers with less than 1 ton/day from gas turbines.

Industrial - Petroleum - The second most significant contributor is the petroleum industry which emits about 110 tons/day. The dominant component of this comes from 7 major and 8 minor refineries, i.e., 103 tons/day. This is the sum of emissions from fluidized bed catalytic crackers, heaters, boilers and other miscellaneous devices. Field operations, mainly H<sub>2</sub>S incineration and transportation, constitute the rest for a total of 24% of Basin winter SOx emitted by petroleum operations.

Industrial - Chemical - The chemicals groups is third most significant with petroleum coke-to-carbon conversion kilns being the dominant source at 26 tons/day. Sulfuric acid and plastics manufacture are significant but smaller sources and all chemical plants together emit 7% of Basin winter emissions.

Industrial - Metals - Iron and steel mills emit the highest emissions in the metal industry, 27 tons/day, with the lead industry contributing 5 tons/day. A major component of these emissions is a steel plant in San Bernardino County, the only producer of ferrous metals from raw ore in the Basin.



TABLE 6-X

**SO<sub>x</sub> INVENTORY BY APPLICATION CATEGORY AND COUNTY**  
**WINTER AVERAGE DAILY SO<sub>x</sub> EMISSIONS, TONS/DAY AS SO<sub>2</sub>**

APPLICATION CATEGORY	L.A.	Orange	River.	San Bern.	San Bar.	Ventura	Basin	Category Total
<b>I. UTILITY</b>								
A. Gas turbine	0.25	0.40		0.00		0.00	0.65	
B. Steam boiler	175.15	24.63		28.52		38.96	267.26	
C. IC eng.-nat. gas trans.	0.00	0.00			0.00	0.00	0.00	
D. Standby turbine-teleph.	0.03	0.00					0.03	
<b>II. INDUSTRIAL-CHEMICAL</b>								267.94
A. Agri. chem. & fertilizers	0.04	0.00					0.04	
B. Plastics	3.44	0.11					3.55	
C. Paints	0.00	0.00					0.00	
D. Pharmaceuticals	0.14						0.14	
E. Sulfuric acid	2.51						2.51	
F. Coke/carbon	26.40						26.40	
G. Other	0.34		0.07				0.41	
<b>III. INDUSTRIAL-MFG. ASSEMBLY</b>								33.05
A. Heavy	0.03	0.00		0.10			0.13	
B. Medium	1.02	0.21	0.06	0.04			1.33	
C. Light	0.28	0.18	0.00	0.08		0.08	0.62	
<b>IV. INDUSTRIAL-METALS</b>								2.08
A. Iron and steel	1.50			25.18			26.68	
B. Aluminum	0.46		0.07			0.00	0.53	
C. Lead and other	5.29						5.29	
<b>V. INDUSTRIAL-MINERALS</b>								32.50
A. Asphalt	0.18		0.02	0.68	0.17	0.02	1.07	
B. Cement and concrete			0.00	0.55			0.55	
C. Glass	2.00	0.50	0.05				2.55	
D. Mineral wool, insulation	0.52			0.07			0.59	
E. Ceramics/clay	0.81		0.15	0.04			1.00	
F. Aggregate and other		0.86				0.54	1.40	
<b>VI. INDUSTRIAL-PETROLEUM</b>								7.16
A. Field operations	0.00	5.72					5.72	
B. Transport, storage	0.17	0.22				0.00	0.41	
C. Refineries	103.36					0.02	103.36	
D. Other	0.05						0.05	
<b>VII. INDUSTRIAL-AGRI. &amp; FOOD</b>								109.54
A. Canning, drying	0.92	0.01					0.93	
B. Citrus		0.04	0.24	0.30		0.00	0.58	
C. Sugar	0.01	0.07					0.08	
D. Other	1.16	0.22		0.00		0.00	1.38	
<b>VIII. INDUSTRIAL-UNCLASSIFIED</b>								2.97
A. Food	0.21	0.00					0.21	
B. Lumber	1.70			0.00			1.70	
C. Other	0.42	0.14	0.09	0.09		0.00	0.74	
<b>IX. COMMERCIAL</b>								2.65
A. Office buildings	0.73	0.20					0.93	
B. Process plants	0.13	0.02					0.15	
C. Retail outlets	0.01						0.01	
D. Other	0.33	0.01					0.34	
<b>X. INSTITUTIONAL</b>								1.43
A. Government	0.75			0.24		0.13	1.12	
B. Hospitals	1.97	0.37		0.31		0.06	2.71	
C. Penal institutions	0.07		0.00	0.10		0.02	0.19	
D. Education	1.26	0.24	0.19	0.02			1.71	
E. Other	0.08						0.08	
<b>TOTALS</b>	<b>333.72</b>	<b>34.15</b>	<b>0.94</b>	<b>56.32</b>	<b>0.17</b>	<b>39.83</b>	<b>465.13</b>	

.00 Sources inventoried but less than 0.01 tons/day

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Industrial - Minerals - Mineral processing comprises the fifth most important source emitting 7 tons/day or 1% of Basin winter emissions. Glass plants and aggregate kilns are the major sources, contributing 55% of the mineral industry winter SOx emissions. Cement plants, although typically operating on high sulfur fuels including coke and coal, are not high sources of SOx, as the sulfur is trapped by both the cement clinkers and by particulate removal devices in the exhaust.

Institutional - Large boilers in hospitals, educational institutions, and government offices are the sixth most significant source of winter SOx emissions. These boilers emit about 6 tons/day or 1.2% of Basin emissions in the winter.

The remaining application categories amount to 9.1% tons/day or 2% of Basin winter emissions. In order of importance, they are Agriculture/Food, Unclassified Industrial, Manufacturing/Assembly, and Commercial.

In Los Angeles County the major SOx sources in order of importance are the utilities, petroleum, coke-to-carbon processing, lead, glass, sulfuric acid, and plastics. Major Basin sources that are minor in this county include cement (none) and the iron and steel industries.

In Orange County the major application sources are utilities, oil field operations, aggregates, and glass. Riverside County has only one possible large source, cement manufacture, but, as mentioned previously, SOx is removed by particulates. (Winter tabulated values are 0 for cement as plant was shut down in December 1974.) San Bernardino County major sources are utilities, and iron and steel. Santa Barbara County shows only two sources in the South Coast Air Basin portion of the county and these are very minor sources of SOx. Ventura County has two major source categories: utilities and aggregates.

The emissions previously presented are based on total sulfur oxides expressed as SO<sub>2</sub>. Detailed distributions of the SO<sub>2</sub> and SO<sub>3</sub> components of these emissions were determined as part of the inventory but complete presentation of SO<sub>3</sub> by application category will not be given.

Complete tabulation of  $\text{SO}_3$  emissions was given in Sections 6.2 and 6.3 for device categories.

Basin total  $\text{SO}_3$  emissions estimated for the summer, winter, and annual daily bases are 12, 18, and 13 tons as  $\text{SO}_3$ /day, respectively. These values compared with the total  $\text{SOx}$  rates of 305, 465, and 342 tons of  $\text{SOx}$  as  $\text{SO}_2$ /day represent conversion rates of 3.2, 3.1 and 3.0% by volume of  $\text{SOx}$  as  $\text{SO}_3$ . A conversion rate of 3% was assumed for all fuel burning devices as discussed in Appendix G, and test results indicate that devices other than fuel burning also average near the 3% level.

#### 6.4 SOx Inventory by Geographical Location

The emissions from point sources rated over 10 MMB/h or emitting more than 2 lb SO<sub>2</sub> per hour have been determined for 10 kilometer square grids (38.6 square miles). The resultant summer, winter, and annual average daily SOx emission distributions are presented in Figures 6-1, 6-2, and 6-3, respectively.

Of the total of 281 full or partial grid squares in the Basin (8600 sq. mi), sources with a potential for emitting 2 lb SOx/hr or more were found to be concentrated in 61 grid squares or 25% of the Basin land area.

Summer emissions totalling 305 tons as SO<sub>2</sub> per day are emitted in 29 grid squares (1000 sq. mi) with sources emitting 0.1 tons/day or more. Figure 6-1 indicates that 46% of the summer emissions come from three grid squares in the south portion of Los Angeles County. These three squares and two additional squares close by account for 56% of the emissions. One square in San Bernardino County is second in order of summer emissions and one square in Ventura County is fifth.

Winter emissions, shown in Figure 6-2, show a wider distribution, over 55 grid squares (1900 sq. mi), compared with summer rates as more fuel oil is burned. In spite of this wider distribution, 5 grid squares in south Los Angeles County still account for 61% of the Basin winter rates.

Annual emissions, Figure 6-3, have a distribution that is intermediate between the more concentrated summer rates and more widely distributed winter rates. Emissions are concentrated in 34 grid squares (1130 sq. mi) and again emissions are highest in 5 grids in south Los Angeles County (61%) and one square in San Bernardino County.

Table 6-XI lists the major grid squares ordered by winter daily emissions for grid squares with emissions of 1 ton/day or more. The major city in each square is indicated and the type of major sources is noted for each. It is apparent that the squares with largest SOx

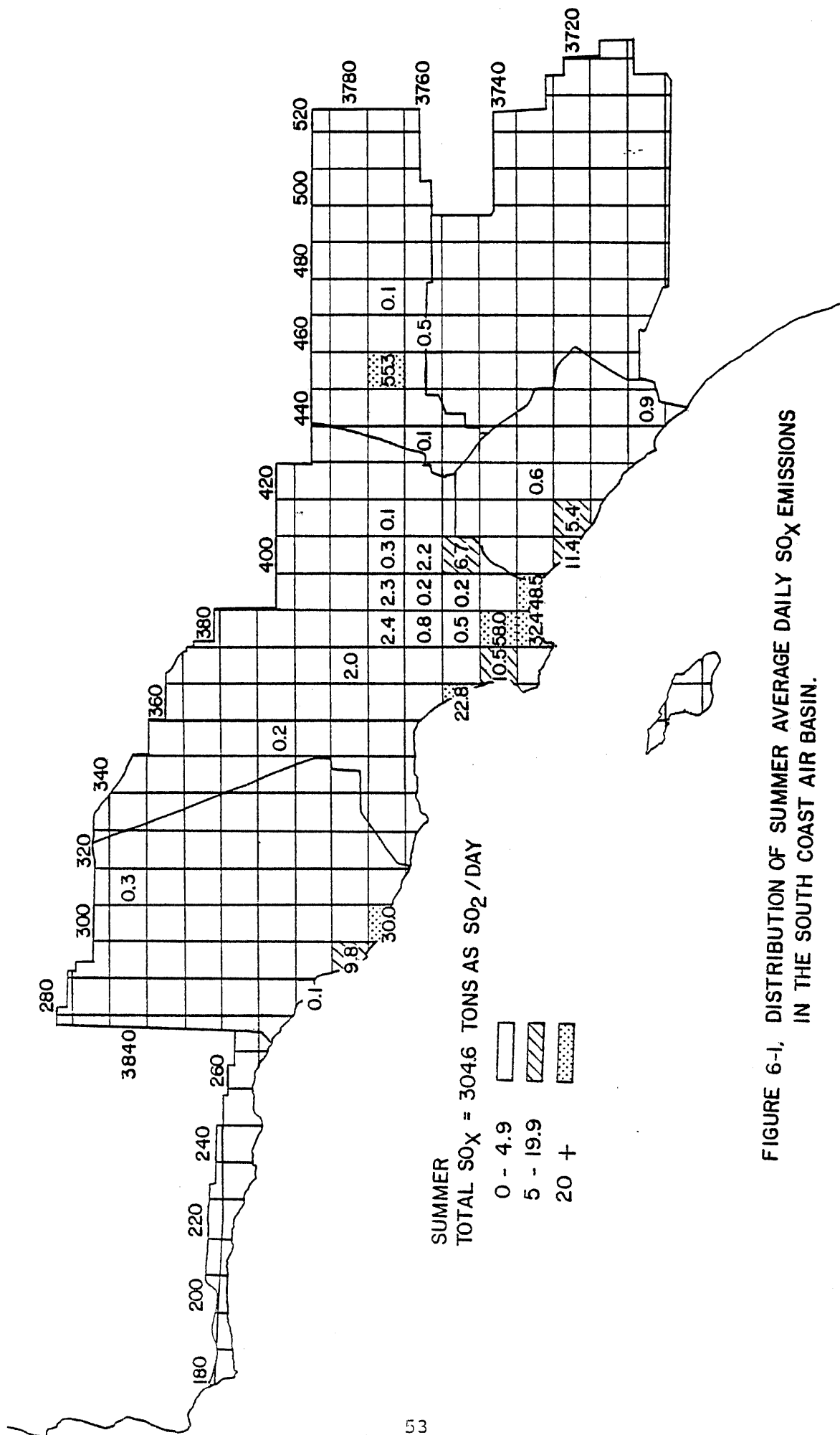


FIGURE 6-1, DISTRIBUTION OF SUMMER AVERAGE DAILY SO<sub>x</sub> EMISSIONS  
IN THE SOUTH COAST AIR BASIN.

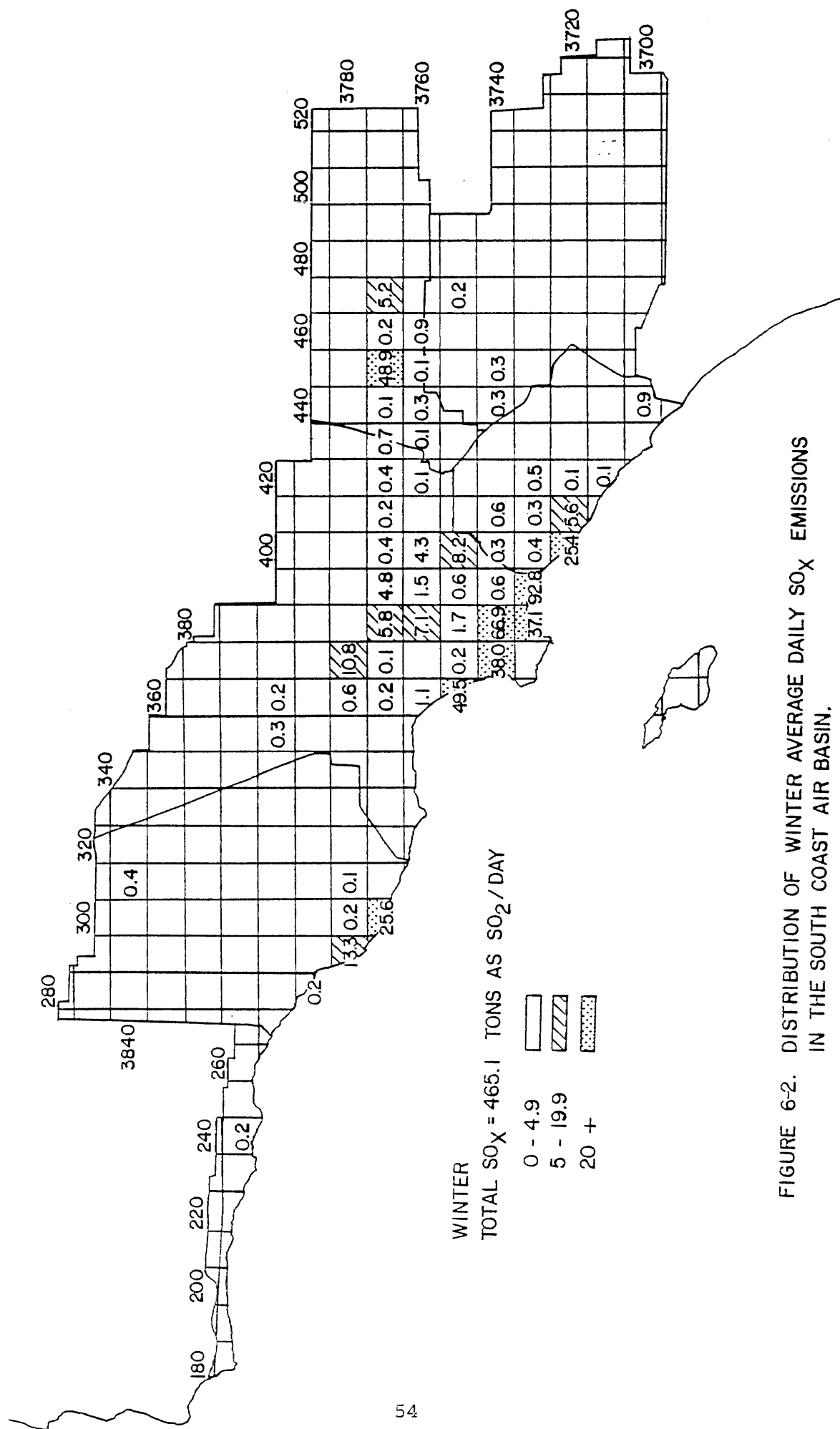


FIGURE 6-2. DISTRIBUTION OF WINTER AVERAGE DAILY SO<sub>x</sub> EMISSIONS IN THE SOUTH COAST AIR BASIN.

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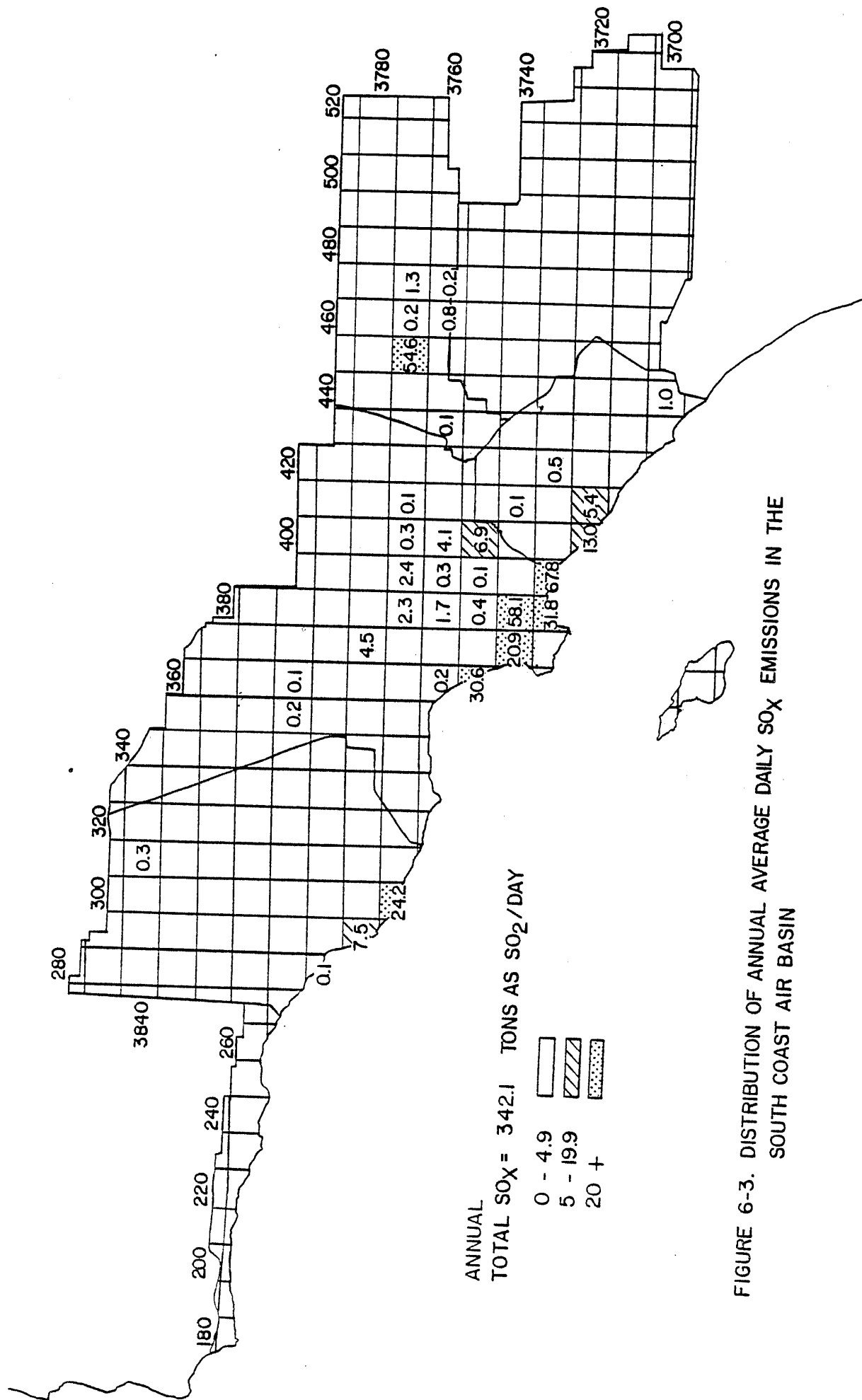


FIGURE 6-3. DISTRIBUTION OF ANNUAL AVERAGE DAILY SO<sub>x</sub> EMISSIONS IN THE SOUTH COAST AIR BASIN

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TABLE 6-XI

SOx INVENTORY GEOGRAPHIC DISTRIBUTION  
AVERAGE DAILY SOx EMISSIONS BY 10 km GRID SQUARES

Grid Square		Major City	County	SOx Emissions			Major Source Type
Horiz.	Vert.			Tons/Day			
				Aug.	Dec.	Annual	
390	3730	Long Beach	LA	48.5	92.8	67.8	Power plant
380	3740	Paramount	LA	58.0	66.9	58.1	Refinery, metal, chemical plant
360	3750	LA International	LA	22.8	49.5	30.6	Power plant, refinery
450	3770	Fontana,	S.Ber	55.3	48.9	54.6	Power plant, metal plant
370	3740	Torrance	LA	10.5	38.0	20.9	Power plant, refinery
380	3730	LA Harbor	LA	32.4	37.1	31.8	Power plant, refinery, carbon plant
300	3770	Point Magu	VT	30.0	25.6	24.2	Power plant
400	3720	Huntington Beach	OR	11.4	25.4	13.0	Power plant
290	3770	Oxnard	VT	9.8	13.3	7.5	Power plant
380	3780	Burbank	LA	2.0	10.8	4.5	Power plant
400	3750	Whittier	LA	6.7	8.2	6.9	Refinery
380	3760	Downtown L.A.	LA	0.8	7.1	1.7	Metal plant, glass plant
410	3720	Costa Mesa	OR	5.4	5.6	5.4	Oil field
380	3770	Glendale	LA	2.4	5.8	2.3	Power plant
470	3770	San Bernardino	S.Ber	0.1	5.2	1.3	Power plant
390	3770	Pasadena	LA	2.3	4.8	2.4	Power plant
400	3760	El Monte	LA	2.2	4.3	4.1	Metal plant
380	3750	Watts	LA	0.5	1.7	0.5	Glass Plant
390	3760	East L.A.	LA	0.3	1.5	0.3	Glass Plant
360	3760	Santa Monica	LA	0.0	1.1	0.2	University
440	3700	N. San Clemente	OR	0.9	0.9	1.0	Aggregate plant
Remaining Grids				2.4	10.6	3.0	
Basin Total				304.7	465.1	342.1	



emissions are those with power plants, refineries, carbon plants, metal plants, and aggregate kilns.

The tables and figures presented in this section include only major point sources and contributions from small devices, such as combustion devices rated at less than 10 MMBtu/hr, are not included. A previous ARB study on NOx emissions (Ref. 1) provided data on area source distributions as related to natural gas consumption, population, income and industrial/commercial activity. A review of these data shows that the total Basin SOx contribution from distributed sources is less than 0.5 tons of SO<sub>2</sub>/day with the largest grid square, 370 horizontal, 3740 vertical\*, contributing only 0.01 tons of SO<sub>2</sub>/day. It is assumed that all these sources remain on natural gas all year and are firm gas users that will continue to be served with natural gas.

Emissions of SO<sub>3</sub>, Figure 6-4, are presented for the winter average daily rates to emphasize the emissions during most prevalent use of oil. With future increased oil use, the summer and annual emissions will approach current winter levels. Of 49 grids with potential for SO<sub>3</sub> emissions, 31 exceed 0.01 tons of SO<sub>3</sub>/day (20 lb of SO<sub>3</sub>/day) in the winter. As with the total SOx, 5 grids in south Los Angeles County account for 63% of the emissions with one grid each in Ventura and San Bernardino Counties contributing a total of 14%. Maximum emissions are 3.5 tons/day in the Long Beach grid square that is also the area of highest total SOx emissions.

To place the foregoing SOx and SO<sub>3</sub> emissions in rough perspective with automobile emissions resulting from sulfur in the gasoline, data for 1969 Los Angeles street and freeway travel (Ref. 39) indicate average street traffic in Los Angeles was about 23,000 vehicles miles

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\*Grid square designations refer to the Universal Transverse Mercator grid system and grid square numbers refer to the intersection of integer 10 km grid square lines at the southwest corner of the respective grid square.

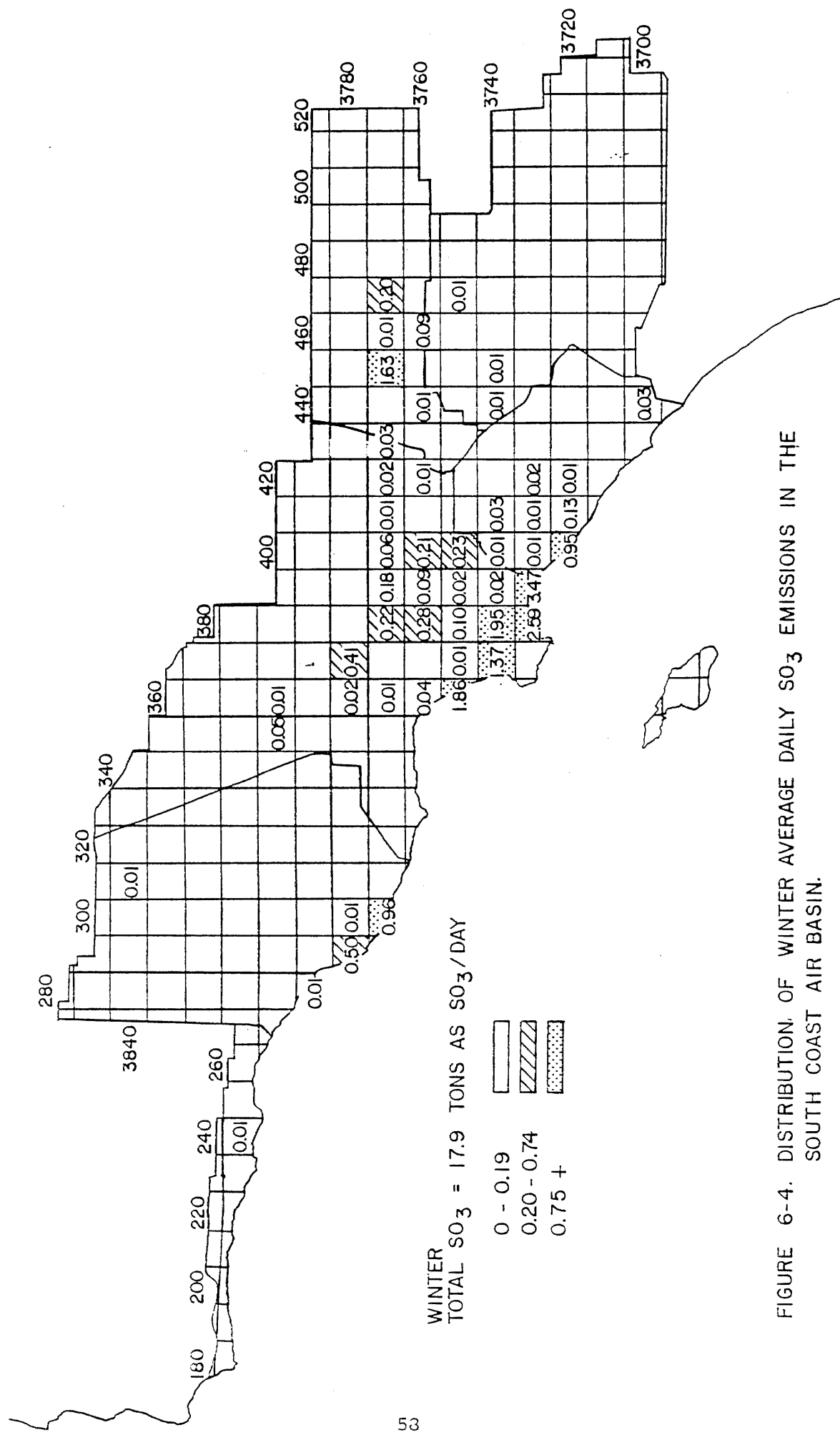


FIGURE 6-4. DISTRIBUTION OF WINTER AVERAGE DAILY SO<sub>3</sub> EMISSIONS IN THE SOUTH COAST AIR BASIN.

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per day per square km (VMPD/km<sup>2</sup>) and for the peak central LA area is about 62,000 VMPD/km<sup>2</sup>. For areas with freeways, the 1969 values were slightly more than double, 56,000 and 139,000 VMPD/km<sup>2</sup> for average and maximum, respectively. These values have increased about 15% in LA from 1969 to 1974 (Ref.38 ). Assuming 13 mi/gal and 0.05% sulfur fuel, total SOx emissions in a 10 km square grid with no freeways would average 0.6 tons of SOx as SO<sub>2</sub>/day with a maximum of 1.6 tons/day. For grids with freeways, the added VMPD/km<sup>2</sup> is about 5/9 the increase in VMPD/km<sup>2</sup> for freeways over street-only values quoted above. The referenced data was based on 3.22 km (2 mi) grids and there are about 9 of these grids in the 10 km grid, of which an average of about 5 show freeway traffic. Emissions of SOx in these grids then average about 1 ton/day with a maximum of about 2.5 tons/day of SOx.

From the geographic distributions of SOx, stationary source average emissions in grids where there are SOx emissions is about 10 tons of SOx/day per grid. Average stationary source emissions on a geographic basis would then appear to be about 10-15 times vehicle emissions in areas that would have both average traffic and average stationary emissions. Examination of the SOx maps however, shows no "average" grids. Winter SOx emissions are either less than 8 tons/day or greater than 25 tons/day in the central Basin. For the grids in central Los Angeles where winter stationary emissions range from 0.3 to 8 tons/day per grid and there is heavy freeway and street traffic at about 2 tons/day, the ratio of stationary-to-vehicle sources on a grid basis could range from about .1 to 4. It is not the purpose of this comparison to draw conclusions regarding air quality but simply to point out that one cannot apriori assume that because stationary source emissions ranged from 305 to 465 tons/day in the Basin during 1974 that these sources are 4 to 6 times more important from a control standpoint than the 70 tons/day of SOx emitted by mobile sources according to the various APCD estimates.

Similar comments can be made regarding the SO<sub>3</sub> component of the SOx emissions. With conventional auto exhaust systems, although no specific data were found, it is estimated that current stationary

to mobile source  $\text{SO}_3$  emissions percentage contributions are roughly equal to total  $\text{SOx}$  percentages. However, with continued increase in vehicles using catalytic converters, this picture can be expected to change significantly. Winter levels of  $\text{SO}_3$  emissions from stationary sources range from 0.01 to 3.5 tons/day of  $\text{SO}_3$  per 10 km grid with central LA levels averaging about 0.3 tons/day. At the average freeway-grid vehicle emission rate of 1 ton/day of total  $\text{SOx}$  as  $\text{SO}_2$  and a 3% volume fraction of  $\text{SOx}$  as  $\text{SO}_3$ , vehicle emissions would be only 0.038 tons of  $\text{SO}_3$  as  $\text{SO}_3$ /day. However, complete eventual incorporation of catalytic conversion may increase the  $\text{SO}_3$  percent to about 30% of total  $\text{SOx}$  (based on emission factor data in Ref. 39), and vehicle emissions would rise to equal average central LA stationary source  $\text{SO}_3$  levels and far exceed stationary source emissions in other areas. The geographic data presented here is an important input to the meteorological assessments necessary to determine the actual importance of each emission source to air quality.

## 6.5 Seasonal Variation

The data discussed in the previous sections were presented in terms of typical daily values for summer and winter days of relevance to the unique Basin meteorology. A detailed assessment of SOx emissions from each source on a day-to-day or month-to-month basis would encompass far more effort than would be of benefit to the objectives of this program. Data are, however, available from the LA APCD for utility, and refinery fuel use and emissions on a daily basis and for about 300 industrial plants on a monthly basis. Additional data from other counties are available for utility fuel use on a monthly basis. A previous ARB study on Basin NOx emissions provided a detailed assessment of total Basin seasonal fuel use and NOx emissions for the time period of July 1972 to June 1973. The fuel use distribution is shown in Figure 6-5. Figure 6-6 shows similar data updated to calendar year 1974 including oil, natural gas and refinery gas use for utilities and refineries. Only the reported use of industrial fuels for Los Angeles County has been included since commercial and residential natural gas use is of little significance to SOx emissions, and similar data for other counties was not as complete.

Comparing the two figures provides some insight into the effect of the energy crisis on fuel use in the Basin. Figure 6-5 for 1972/1973 shows a high peak of natural gas use by the utilities during July and August and correspondingly lower use of oil. During the winter months the situation is reversed with low gas use and high oil use by the utilities. Figure 6-6 shows January utility fuel use to be typically high in oil use but total fuel use is down by 10% from January 1973 (Figure 6-5). The largest impact of the energy crisis and simultaneous high hydropower imports is seen in Figure 6-6 in February, March and April of 1974 with total fuel use by utilities down about 20% from the same months in 1973. Gas use in the summer of 1974 increased but to only about one-half the 1972 level and the summer fuel use is about equally split between gas and oil. Total utility fuel use increased gradually through 1974 and in December 1974 was about

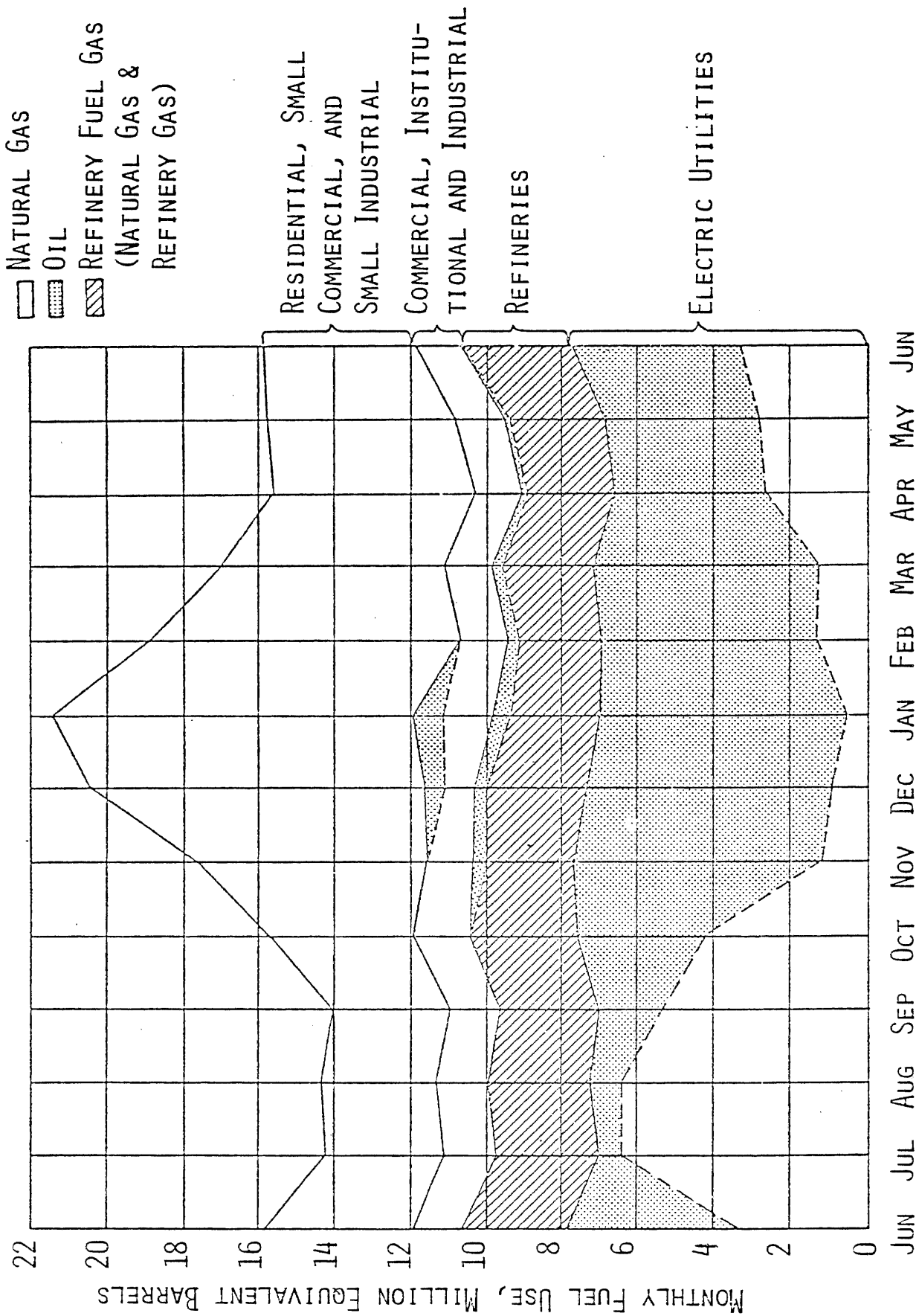


FIGURE 6-5. MONTHLY VARIATION OF FUEL USE FOR THE PERIOD JULY 1972 - JUNE 1973  
FOR THE SOUTH COAST AIR BASIN.

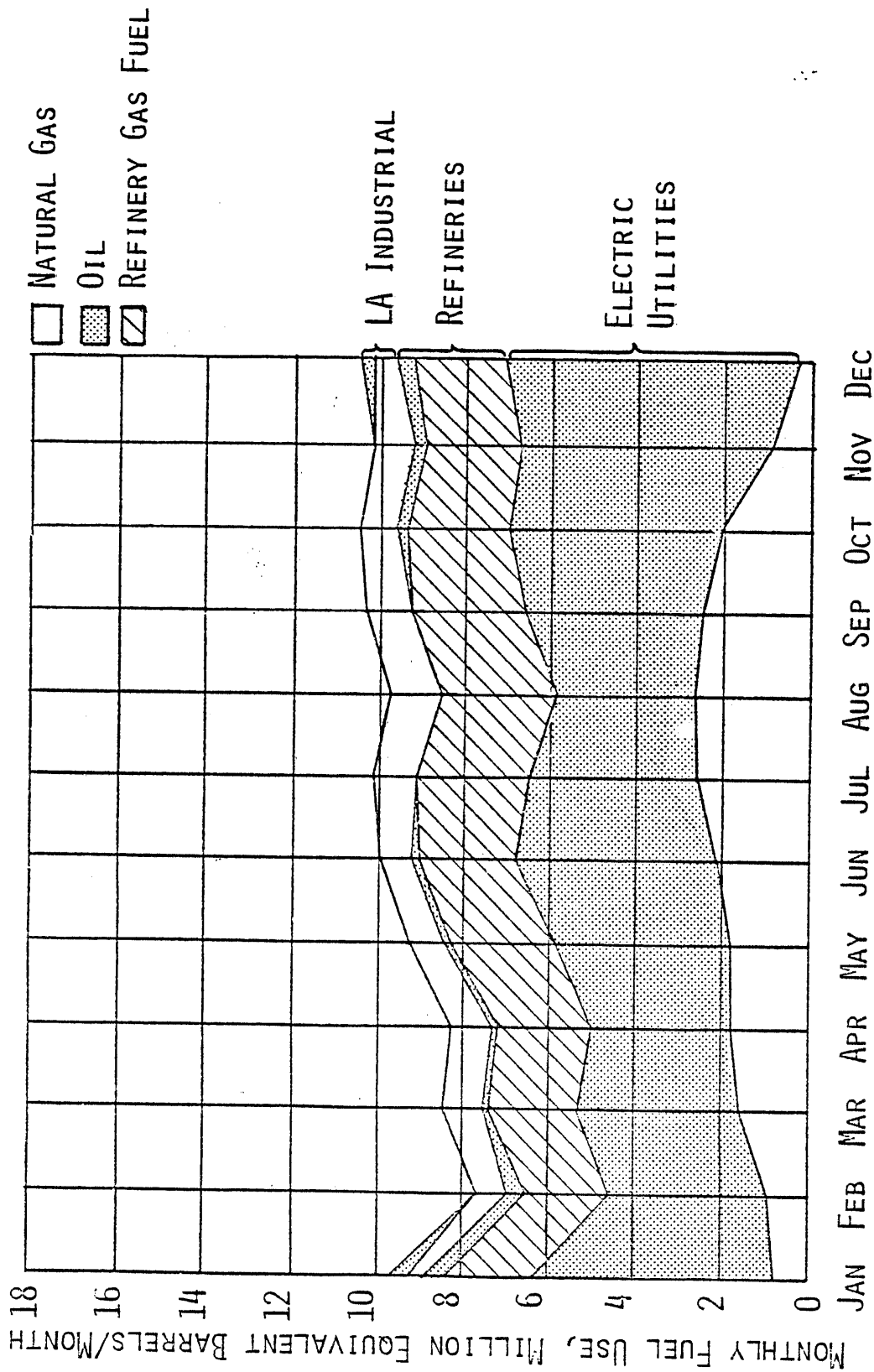


FIGURE 6-6. MONTHLY VARIATION OF FUEL USE IN UTILITIES, REFINERIES, AND LOS ANGELES INDUSTRIES FOR THE SOUTH COAST AIR BASIN IN 1974 (CALENDAR YEAR).

the same as December 1973 with most of the fuel supplied as oil. Refinery gas fuel use remains relatively constant throughout both years shown with slightly reduced use in 1974 compared with the 72/73 period.

Figure 6-7 presents the SOx emissions for 1974 based on the fuel use of Figure 6-6 and, in addition, estimated SOx emissions from material processing plants as determined in the inventory. The December, 1974 SOx emissions shown in this figure are 14,000 tons as SO<sub>2</sub>/month. This corresponds to 450 tons/day daily average as compared with the inventory winter value of 465 tons/day (Table 6-I).

The August, 1974, SOx emissions shown in Figure 6-6 are 9200 tons/month or about 296 tons/day. This is within 3% of the inventory value of 304 tons/day in Table 6-I. This compares with a value of 159 tons/day estimated in the preliminary inventory phase of this program (Appendix C) developed on the assumption that all combustion sources burned gas during the summer. This is the most dramatic result of natural gas curtailment indicating an SOx increase of about 140 tons/day in the summer of 1974 as compared with past years when gas was in fact the prevalent summer fuel.

The addition to seasonal variation of SOx emissions estimated for material processing included in Figure 6-7 is based entirely on use of the inventory annual daily average of about 145 tons/day as very little month-to-month change is seen in these sources, and a detailed seasonal assessment would not materially contribute to the inventory.



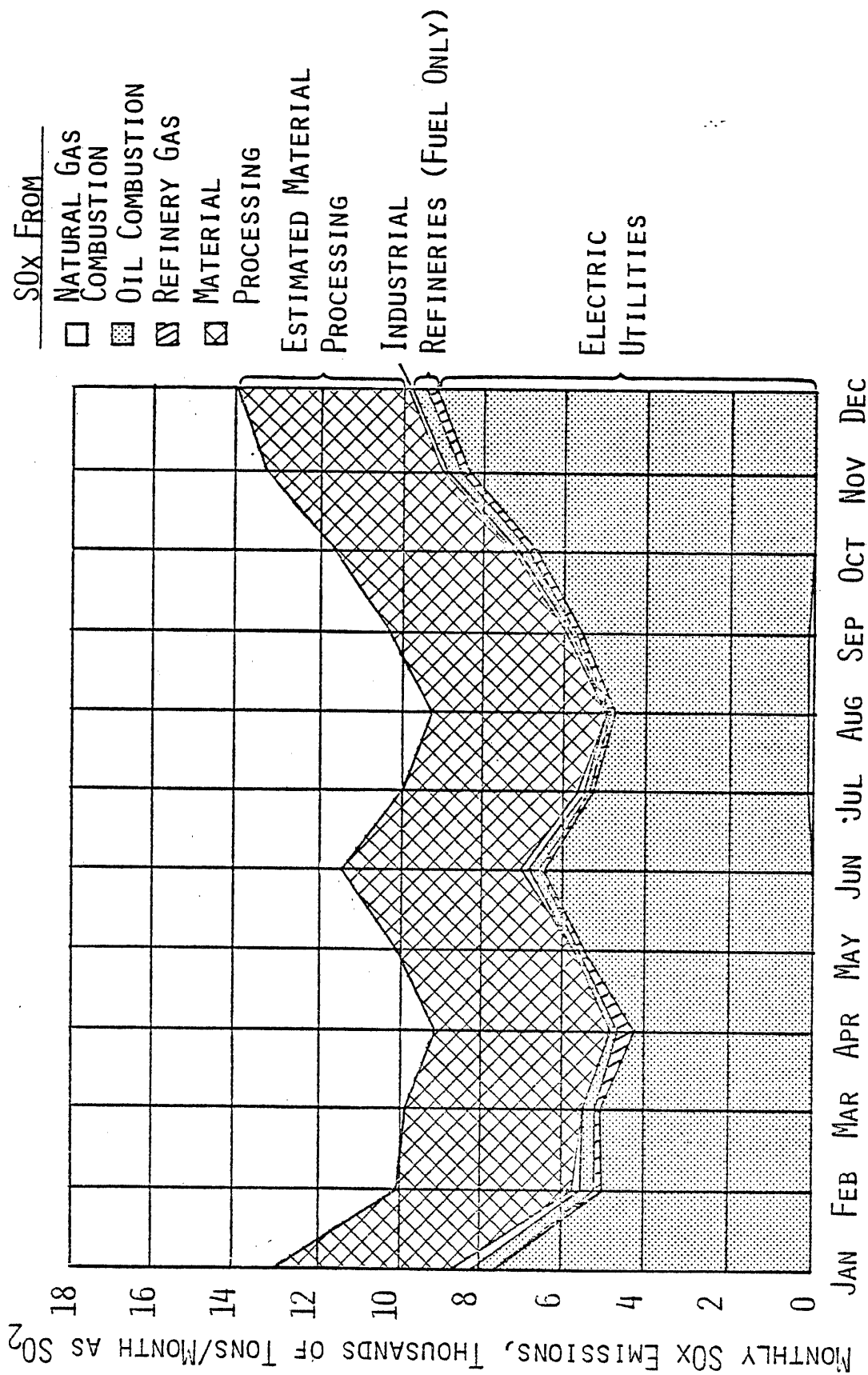


FIGURE 6-7. MONTHLY VARIATION OF SO<sub>x</sub> EMISSIONS FOR THE SOUTH COAST AIR BASIN IN 1974 (CALENDAR YEAR).

## 7.0 EMISSIONS FORECAST

The current rapidly changing picture with regard to the use of fuel oil in the Basin, according to data gathered for this program, is projected to result in an increase in annual average SOx emissions from 342 tons/day in 1974 to 743 tons/day in 1980, a 117% increase. Even more significant are projected increases in the summer average daily emissions from 305 tons/day in 1974 to equal the annual average 743 tons/day in 1980. This is a 144% increase reflecting the fact that summer emissions, previously lower because of natural gas burning, are projected to increase to levels near those in the winter where oil has been the predominant fuel in recent years. The growth in total SOx will be paralleled by a growth in SO<sub>3</sub> emissions resulting in increased sulfate levels during the same period when sulfate emissions from mobile sources are on the rise as the result of catalytic converters.

### 7.1 Forecast SOx Emissions 1975-1980

Data gathered for this program included projections for each major SOx source of growth in production rate from which resultant emissions growth could be determined and also additional installations of SOx control devices that would reduce emissions. Appendix N contains an analysis of Basin natural gas supplies.

Projected emissions for specific device categories clearly show that the SOx emissions growth is largely from utility boilers as seen in Table 7-I. The projected increase is the result in a growth in the use of low sulfur fuel oil from 46 million barrels in 1974 to about 106 million barrels in 1980. The sharpest increase in oil use occurs in 1975 with a projected use of 83 million barrels. After 1976 almost the entire energy requirements for electric generation in the Basin will be obtained from oil.

The curtailment of natural gas is expected to sharply increase 1975 emissions from commercial, institutional, and industrial boilers as the result of projected increases in energy requirements coupled with a reduction in gas availability from 95% to 0-45% of total energy required, projected by the Southern California Gas Company (Ref. 40). The SOx increase from 1975 to 1980 is based on a SCGC projected increase in "industrial interruptible" energy requirements of 10% (see Appendix N).

TABLE 7-I

FORECAST OF ANNUAL AVERAGE SOX EMISSIONS FROM STATIONARY SOURCES  
IN THE SOUTH COAST AIR BASIN

	SOx, Tons as SO <sub>2</sub> /Day						
	1974	1975	1976	New Gas Supplies		No New Gas Supplies	
				1979	1980	1979	1980
Combustion Sources							
Boilers - Utility	171.8	315	350	391	404	444	459
Refinery	3.1	3	4	7	5	10	10
Other Industrial	8.2	10	13	19	15	35	35
Coml/Inst	0.4	1	3	6	4	12	14
Process Heaters - Petroleum	7.1	8	15	27	17	36	36
Internal Combustion Engines	0.4	1	1	1	1	5	5
Waste Gas Incineration	5.4	5	5	5	5	16	16
Total, Combustion	196.4	343	391	456	451	558	575
Material Processing Sources							
Furnaces and Kilns	66.3	63	65	78	74	80	80
Pet. Catalytic Cracking	45.6	49	49	49	49	49	49
Sulfur Recovery	30.7	31	3	3	3	3	3
Sulfur Acid Mfg.	2.6	3	3	3	3	3	3
Miscellaneous	0.6	1	2	3	3	3	3
Total, Material Processing	145.8	147	122	136	132	138	138
Total, All Stationary Devices	342.2	490	513	592	583	696	713
Firm Sources	0.5	0.5	0.6	0.6	0.7	12	30
	342.6	495.5	513.6	592.6	583.7	708	743

5802-432

The SOx emissions from small heaters, boilers and other devices now on firm natural gas are not expected to increase significantly until about 1979 when the complete curtailment of gas may occur if no new gas supplies are obtained.

Increased emissions are projected only for the total Basin as utility growth rates and oil use were not available on a county basis. Although growth in Orange County might be expected to be larger than in the others, no specific data were available.

The growth in SOx emissions for petroleum refinery heaters and boilers is significant. With new gas supplies 1980 emissions are 32 tons/day, and up to 71 tons/day with no new supplies. Although refineries are expected to burn oil in place of current natural gas used, refinery gas will continue to be the predominant fuel. One possible change that could occur would be for the refineries to actually market some refinery gas to external users as a replacement for curtailed natural gas in units not equipped to burn oil. The refineries could then burn more oil in their units equipped to burn oil. The net increase in SOx emissions would then be that resulting from the increased oil used by the refineries and this would add an estimated additional 64 tons/day of SOx emissions if all refinery gas were marketed.

In the group of material processing plants, the growth in SOx emissions is almost entirely due to changes in production rates but with significant fuel switching effects in the Furnace and Kilns category. From 1974 to 1976 there is a significant drop in emissions from sulfur recovery plants as the result of projected final compliance of all units with LA County Rule 53.2.

Events that could materially alter these projections involve primarily the availabilities of natural gas and low sulfur fuel oil and the importing of electrical power such as hydroelectric into the Basin. Projections have been based on substitution of low sulfur fuel oil for natural gas and no significant hydropower imports. Restoration of natural gas or significant hydropower would

lower the projections while requirements to burn high sulfur oil instead of low sulfur oil could result in substantially increased emissions. Also unknown are possible effects of a shift to more uniform SOx emissions regulations as the result of combination of LA, Orange, San Bernardino, and Riverside Counties into a common Southern California Air Pollution Control District.

Thus it is projected that without further stationary source emissions controls in the Basin that emissions from these sources will increase by about 45% in 1975. In 1976 growth in fuel combustion sources will just about be offset by final completion of control of refinery sulfur recovery plants limiting total SOx growth to about 4% from 1975 to 1976. A 14% increase from 1976 to 1980 with new gas supplies results almost entirely from growth in production rates since most large devices will be on 100% oil use by 1976. Complete natural gas curtailment on industrial devices for no new gas supplies would add an estimated additional 159 tons/day in 1980.

## 7.2 Relation of Stationary Sources to Total Basin SOx Emissions

Emissions of sulfur oxides from stationary sources are unique among the various pollutants in that emissions far exceed those of mobile sources. Total mobile source emissions are estimated at 70-75 tons of SOx as SO<sub>2</sub>/day according to various county APCD and ARB inventories (Refs. 27, 33, 35-37) and are therefore only 20% of the 342 tons/day from stationary sources. Of these mobile source emissions, about 40 tons/day are from motor vehicles. Growth in Basin vehicle travel is projected at 3.9% per year based on past data (Ref. 38). At this rate, basin motor vehicle emissions would increase 26% to 50 tons/day in 1980, based on a continued average gasoline sulfur content of 0.054% sulfur (Ref. 27). Implementation of a California Air Resources Board regulation that limits basin unleaded gasoline sulfur content to 0.03% S may not reduce SOx emissions in 1980 because the reduction will be achieved by a comparable increase in leaded gasoline sulfur.

Particular concern is now being expressed regarding that portion of the sulfur oxides that are emitted as sulfuric acid mist that forms

from sulfur trioxide ( $\text{SO}_3$ ) and water vapor, present in all combustion sources exhausts. The concern arises as the result of implementation of catalytic converters in automobiles for reduction of hydrocarbon and carbon monoxide emissions. While these converters are effective in reducing HC and CO emissions, they serve to increase the conversion of fuel sulfur from  $\text{SO}_2$  formed in the combustion process to  $\text{SO}_3$ . This process is optimized at about  $900^\circ\text{F}$  and is precisely the process that is used in sulfuric acid manufacture (See Appendix J). The conversion process in either conventional or catalytic exhaust systems can be expected to vary widely as a function of exhaust composition and temperatures and little specific data are available on these effects. However, it is estimated that about 3% of the fuel sulfur forms  $\text{SO}_3$  in conventional exhausts while in catalytic systems, this increases to about 30% based on emission factors in Ref. 39. Therefore, in 1974 about 2.5 tons of sulfuric acid ( $\text{H}_2\text{SO}_4 \cdot 2\text{H}_2\text{O}$ ) were emitted from Basin conventional exhaust automobiles. As converter use increases, although gasoline sulfur should be reduced, sulfuric acid emissions will rise to about 18 tons/day (as  $\text{H}_2\text{SO}_4 \cdot 2\text{H}_2\text{O}$ ) and could be as high as 30 tons/day if catalyst conversion were as high as 50%.

For comparison with stationary sources, the total 1974  $\text{SOx}$  emissions of 342 tons as  $\text{SO}_2$ /day includes an average of 3.0% by volume of  $\text{SO}_3$  or 22 tons as  $\text{H}_2\text{SO}_4 \cdot 2\text{H}_2\text{O}$ /day. Mobile sources were about 18% of the total sulfuric acid emissions in 1974. In 1980, with stationary sources increased to 743 tons  $\text{SOx}$  as  $\text{SO}_2$ /day with an unchanged 3.1% by volume of  $\text{SO}_3$ , the sulfuric acid emissions are projected to be 48 tons/day and therefore the mobile sources can be expected to increase at a greater rate and approach 40% of all source sulfuric acid emissions.

From the standpoint of air quality as affected by sulfuric acid mist emissions, automotive emissions are considered more critical as emissions are at ground level in highly populated areas. Stationary source emissions are mostly from high stacks and subsequent dilution

may significantly reduce their importance at ground level compared with mobile sources. It is not a specific objective of this program to assess the effects of emissions on air quality but instead to provide the necessary input information to such an assessment as the next logical step. Although mobile and stationary source emission levels are compared here, these comparisons must be tempered with additional understanding of the differences in the character of each source with regard to ambient air quality. With these differences in perspective, Figure 7-1 presents the historic and projected SOx emissions for mobile and stationary sources in the Basin. Historic data are taken from the inventories of various APCD data and data from the California ARB. This figure indicates that 1970 and 1974 were clearly minimums in sulfur oxides emissions, a result of the culmination of sulfur oxides controls (primarily limiting fuel sulfur content, sulfuric acid and sulfur recovery plants), and the unusually high level of importation of hydroelectric power in 1974 balanced against projected substantial increases of fuel oil use beyond 1974. The projections indicate that if new gas supplies do become available, SOx emissions, including mobile sources, will reach a peak of about 680 tons/day in 1979. These new supplies represent the best estimates by SGGC of supply from a number of possible sources and thus are not contingent on one specific project. If none of these sources materialize there will be a very substantial increase in 1980 emissions to about 835 tons/day with further increases possible beyond that year.

As discussed in the next section, there is little hope for reversing the projected future increases short of significant restitution of natural gas supplies, or, failing that, implementation of significantly more stringent controls. If supplies of low sulfur fuel oil cannot meet the demand and high sulfur fuel must be burned, the 743 ton/day projection for stationary sources could well grow to over 1000 tons/day.

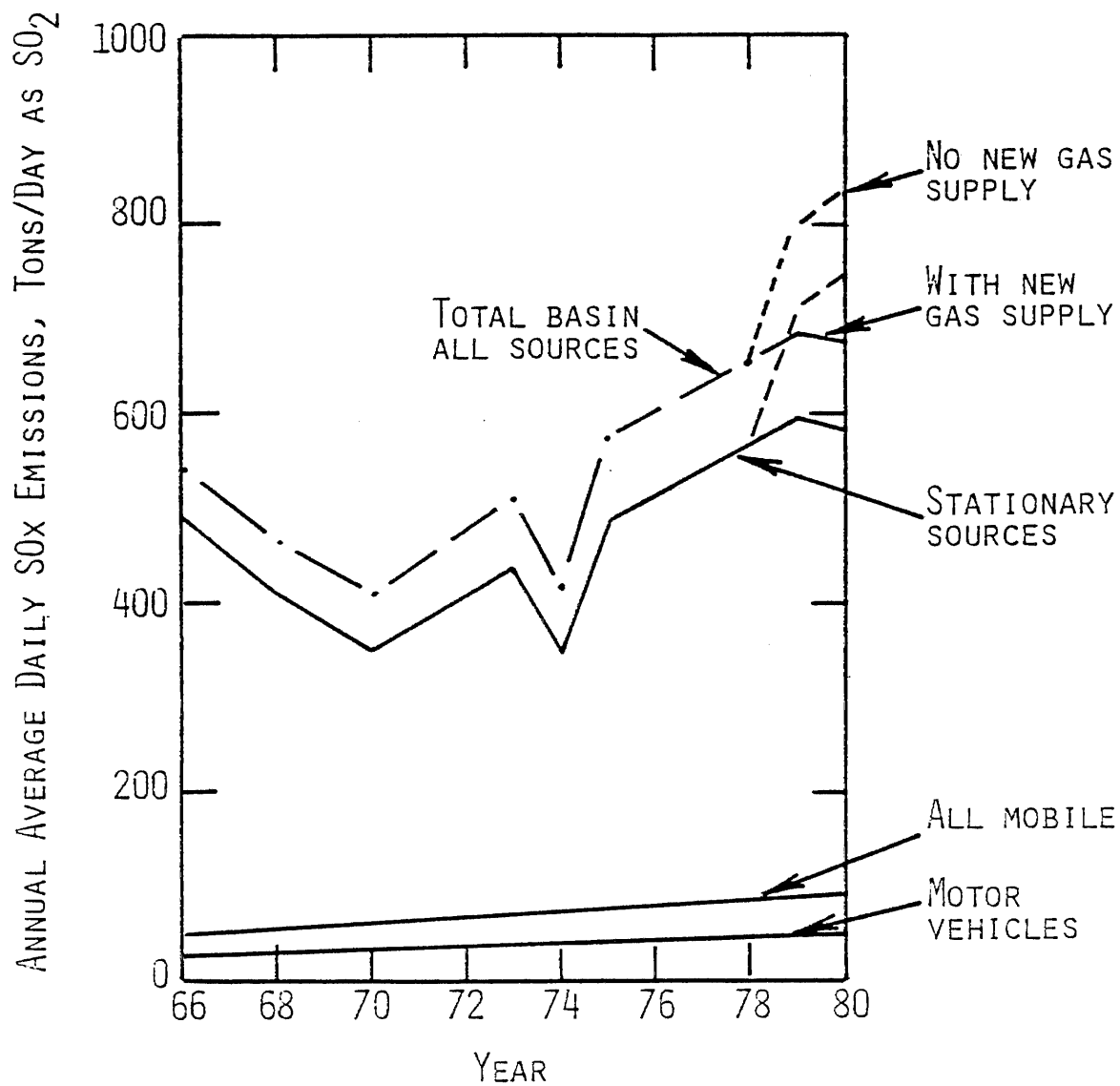


FIGURE 7-1. MOBILE AND STATIONARY SOURCE EMISSIONS OF SO<sub>x</sub> FOR THE SOUTH COAST AIR BASIN.



### 7.3 SOx Related Air Quality Status

A detailed interpretation of the SOx emissions from stationary sources in terms of air quality is beyond the scope and resources of the current program. Such an assessment can only be made with proper application of basin meteorology and consideration of the height, velocities, temperatures and dispersion of emissions from the various sources. Some comment, however, regarding the current state of basin air quality as related to SOx is appropriate to place SOx emissions and projected growth in perspective with respect to need, if any, for limitations of SOx emissions. There are three groups of air quality standard criteria that involve SOx emissions. The first group are ambient concentration standards for gaseous SO<sub>2</sub>. Second are the standards for ambient particulate matter and third are standards for visibility. The latter two standards are influenced by formation of sulfuric acid liquid mist particles and contributions to solid particulate by formation of solid sulfate compounds.

There are 15 specific local, state, and federal standards for gaseous SO<sub>2</sub> that are applicable to basin air quality. These range in magnitude from the 0.03 ppm (80 µg/m<sup>3</sup> annual arithmetic mean) national air quality standard to the 10 ppm (instantaneous) level for LAC APCD emergency third stage alert. Included are two California state air quality standards of 0.04 ppm (24 hr average) and 0.50 ppm (1 hr average). (The standard of 0.04 ppm was increased in 1974 to 0.10 but returned by the ARB to 0.04 in 1975.) Data for 1974 in Los Angeles County (Refs. 97, 98) indicate that, for that year, currently applicable standards were met on all but one day during which the then current 0.10 ppm 24 hr average state SO<sub>2</sub> standard was exceeded by only 0.008 ppm. However, the lower state SO<sub>2</sub> standard, now in effect, of 0.04 ppm was exceeded on 51 days at localized points in the basin. With respect to the national standard of 0.03 ppm AAM, the standard was met with a Los Angeles basin average of 0.017 ppm and a peak of 0.024 ppm at the

Southeast monitoring station. Historical data indicate 1974 SO<sub>2</sub> ambient levels (1 hr average basis) are about one half the peak levels of 1957. That year was also a peak year for SOx emissions from utility boilers when the maximum amount of high sulfur fuel was burned and the emission rate from Los Angeles County power plants was in the range of 250 tons of SO<sub>2</sub>/day. During 1957 the 0.04 ppm 24 hr level was exceeded on about 325 days. This situation apparently contributed to reported episodes of high sulfur smog. Following that peak year, increased natural gas use by utilities and a shift to low sulfur fuel oil in 1967 resulted in the 0.04 ppm level being exceeded on from 30 to 125 days. It would appear that, while currently the primary air quality problem in terms of gaseous SO<sub>2</sub> concentrations concerns the 0.04 ppm state air quality standard, the projected increased SOx emissions as a result of natural gas curtailment threaten a possible return to sulfur smog problems experienced in 1957. The projected 1980 SOx emissions from Los Angeles County power plants is about 265 tons/day (Table G-II, Appendix G) or roughly 10% higher than the 1957 level. Emissions from other stationary and mobile sources resulted in a total of about 550 tons/day being emitted in Los Angeles County in 1957. This compares with about 500 tons/day of SOx emissions projected for all sources in Los Angeles County in 1980 and a total basin projected emissions of 835 tons/day. Utility emissions may exceed 1957 levels, and increased industrial oil burning will more than offset reduced sulfur plant emissions. The significance of the emissions from these various sources to air quality deterioration can only be resolved with appropriate information on meteorology and dispersion. The influence of meteorology is of utmost importance. While 1957 was a peak year for both utility emissions and ambient concentrations, the total SOx emissions from all sources in Los Angeles County was higher (about 800 tons/day) in 1956 during which the sulfur smog problem was apparently not as severe compared with 1957 when total emissions were about 550 tons/day. The year 1956 was the earliest period for which data was available so no conclusions regarding earlier years can be drawn.

Based on a brief review of the ambient data, and an admittedly tenuous assumption that ambient  $\text{SO}_2$  levels are directly proportional to  $\text{SOx}$  emissions, it would appear that for increases in  $\text{SOx}$  emissions over 1974 levels of somewhere between 70% and 117%, the basin air quality standards may be increasingly exceeded. Based on estimated projections, a return to 1957 smog episodes appears possible and definite if low sulfur oils must be replaced with high sulfur oil. This indicates that the major efforts for air quality control in terms of gaseous  $\text{SO}_2$  concentrations need to be directed to  $\text{SOx}$  emissions growth limitation should such growth, in fact, materialize, and to the increased provision of low sulfur fuels to meet the projected requirements.

A further complicating factor relates to the seasonal nature of  $\text{SOx}$  emissions and the differing character of summer and winter smog. The limited historical data reviewed did not provide sufficient information on the relative summer and winter  $\text{SOx}$  emissions and ambient air quality data. The general trend in past years was the burning of oil in winter months and gas in the summer. The projected increases in fuel burning emissions are greatest in the summer months when smog is most severe. However, sulfur smog is apparently most dangerous in humid winter months and projected winter emissions are only 60% higher than previous years compared with a 300-400% increase in summer emissions. These differing characteristics require careful consideration in any projections of future air quality.

For suspended particulate matter there is one state standard for visibility and twelve state and national standards applicable to particulate matter concentrations. The state visibility standard is not met when visibility is less than 10 miles and relative humidity is less than 70%. The particulate matter concentrations standards range from the  $60 \mu\text{g}/\text{m}^3$  annual geometric mean (AGM) state and national (secondary) standards up to  $1000 \mu\text{g}/\text{m}^3$  for the national emergency

episode criteria for significant harm to health. In relation to the  $60 \mu\text{g}/\text{m}^3$  AGM standard, the data for the basin (Ref. 41) indicate the standard was exceeded by 42% in 1973 but there is a definite downward trend that suggests the standard will be reached before 1980 on a basin wide average basis. However, maximum local concentrations in 1973 exceeded the standard by about 170%. A study of aerosol formation (Ref. 42), conducted for the ARB to characterize the composition of aerosols (particulate matter), indicated that about 50% of this matter is of secondary origin, that is, formed in the atmosphere from gaseous sulfur oxides, nitrogen oxides, and organics. The remaining 50% is from primary origin, that is, emitted directly from various man-made or natural sources. The secondary matter is of even greater significance because it is concentrated in the 0.1 - 1.0 micrometer particle size that most influences visibility. Furthermore, the contribution from sulfates as compared to nitrates or organics is apparently more significant in this same size range. The sulfate portion of atmospheric particulate matter is reported (Ref. 41) to range from 10-15  $\mu\text{g}/\text{m}^3$  on a basin average basis but local maxima are considerably higher. This data indicates that while the current particulate matter ambient concentration trend is downward that future increases in SOx emission may cause a slowing or reversal of this trend. The specific levels of pollutant emissions (including SOx) required to achieve the standards are not yet entirely clear but the need for attention to SOx emission in relation to atmospheric sulfate has been clearly established.

With regard to visibility standards, the data reviewed were insufficient to define trends or concentration limitation requirements. However, the state visibility standard was exceeded in Los Angeles County on 310 days in 1974 (Ref. 32). With sulfates clearly identified as a major factor in visibility reduction by particulate matter, it is evident that attention will increasingly be directed toward limitation of gaseous SOx emission as a precursor to secondary formation of this material. This is reflected in the recent passage of a new state standard of  $25 \mu\text{g}/\text{m}^3$  (24 hr) for sulfates in particulate matter.

In view of the very complex nature of atmospheric reactions and dispersion as relate SOx emissions to the three groups of ambient air quality standards discussed above, it was not possible in the current program to establish a definitive criteria for required reductions or growth limitation as relate to potential SOx reduction methods discussed in the next section of the report. However, it is clear that current levels of SOx emissions are in some part responsible for the standards on particulate matter and visibility currently being exceeded. In addition, while the current standards for atmospheric gaseous SO<sub>2</sub> concentrations are only exceeded on a few days per year, projected growth in stationary source emissions, primarily from power plants, may result in a considerable worsening of this situation. Projected SOx emissions are expected to reach a peak about 1980. No specific data beyond 1980 was available but increased power importation should ease the problem some what. The 1980 peak is expected to be higher than the worst SOx-related air quality year, 1957. The projected growth is of sufficient magnitude as to require very careful attention to the effects on air quality, particularly in the summer months.

## 8.0 DISCUSSION OF POTENTIAL AND COSTS OF REDUCING EMISSIONS

### 8.1 Cost, Cost Effectiveness Approach

Separate discussions have been made of the potential for reduction of SOx emissions in each of the seven source categories considered in this program,

- . combustion sources
- . oil refinery fluid catalytic cracking units
- . sulfur recovery plants
- . sulfuric acid plants
- . petroleum coke kilns
- . metallurgical plants
- . mineral plants

(appendices G through M). Each of these categories has been considered as to the applicability of the established emissions reduction techniques such as fuel allocation, fuel desulfurization, stack gas desulfurization, and process modification. The quantitative potential SOx reduction for each source category has been assessed, as well as the aggregate costs involved, and the resultant potential cost effectiveness. The results are brought together and discussed later in this section.

In order to make meaningful comparisons of the various emissions reduction options it was necessary to put them on a common basis, one that could be compared with other options for reducing Basin emissions. Chosen was a cost/benefit ratio defined as dollars of annual cost per tons of SOx prevented or reduced. SOx is counted as SO<sub>2</sub> with a molecular weight of 64. Since there was generally some uncertainty in the estimate of the amount of SOx that could be prevented the value selected was consistently estimated conservatively low. Likewise since there was even more uncertainty in establishing generalized costs for the reductions, these were generally estimated conservatively high. Thus it is believed

the cost/benefit ratios established are conservatively high. In a number of cases the reduction techniques considered, while firmly established for some devices have not in fact been demonstrated as being feasible for some of the specific devices considered in this study. Hence the basic feasibility of some of the techniques for some of the devices requires demonstration before their projected reductions can be counted on.

With regard to the estimation of costs, in each instance where annual costs were not available from existing estimates, costs were composed of an annualized fraction of the capital cost, an annual cost to cover the consequence of any resultant auxiliaries or off site requirements, and an annual maintenance cost. The capital cost was the sum of hardware and construction costs, and engineering costs for implementation of the modification. For most cost/benefit ratio calculations the capital cost was annualized at the rate of 20% per year as they have been for cost effectiveness studies by EPA and others. In some cases a lower annualization percentage could logically have been selected and would have resulted in somewhat improved cost/benefit ratios. Fuel costs were dealt with by assuming the cost of natural gas constant at \$0.50/MMB, low sulfur oil at \$1/MMB (\$6.30/BBL) up to 1973 and at \$2/MMB (\$12.60/BBL) in 1974 and beyond. Maintenance was taken as a fixed 5% of the capital investment.

Where possible all costs were adjusted to a July 1975 basis with an appropriate cost index. The basic cost effectiveness evaluation methods are similar to those used in a previous study of NO<sub>x</sub> (Ref. 1) with the exception that cost effectiveness has been expressed in \$/ton as opposed to a reciprocal relation of lb/\$ used in Reference 1. Comments received on the work of Reference 1, performed by KVB, suggested that the \$/ton relation would be most useful to the widest number of people (1 lb/\$ = \$2000/ton).

## 8.2 Cost Effectiveness of Currently Implemented Emissions Controls

In a previous study of NO<sub>x</sub> (Ref. 1) the cost effectiveness of various stationary source potential reduction methods was put into perspective with the automotive NO<sub>x</sub> retrofit program cost effectiveness as a criteria for judgment. There are three events that provide a similar perspective for stationary source emissions of oxides of sulfur: (1) the restriction of oil fuel sulfur content to 0.5% by Rule 62 in Los Angeles County and similar rules in other counties, (2) regulation of sulfur recovery and sulfuric acid plants to 500 ppm of sulfur compounds by Los Angeles County Rules 53.2 and 53.3, and (3) the imposition of a 300 ppm sulfur limit by 1980 on automotive unleaded gasoline to restrict sulfuric acid mist formation from catalytic converters with a goal of 100 ppm by 1984.

Restriction of fuel oil sulfur content for electric utilities began about 1967. As shown in Appendix F the manufacturing cost to desulfurize the fuel at that time was about \$0.75 per barrel to reduce from 2.0% to 0.5% sulfur. This resulted in a cost effectiveness at that time of about

$$CB = \frac{2000 (\$/BBL)}{7 (g) (\Delta\% S)} = \$160 \text{ per ton}$$

where: CB = cost/benefit ratio, \$ per ton of SO<sub>x</sub> as SO<sub>2</sub> removed

\$/BBL = desulfurization cost, \$ per barrel

g = specific gravity of fuel oil, 0.9

Δ% S = sulfur content reduction, 2.0 - 0.5 = 1.5

In the 1967-1969 time period the Los Angeles County utility fuel oil consumption was about 10 million barrels per year (Ref. 27). Assuming high sulfur oil at 2.0% the 0.5% rule resulted in a total SO<sub>x</sub> reduction of 100 million pounds of SO<sub>x</sub> as SO<sub>2</sub> or an average of 135 tons of SO<sub>x</sub> as SO<sub>2</sub> per day reduction. At 1974 total oil consumption of 46 million barrels, this represents a 600 ton/day prevention of SO<sub>x</sub> at an uncontrolled sulfur content of 2.0% S or 400 tons/day if 1.5% S oil were burned.



At 1975 cost levels, cost/benefit ratio of this reduction would increase to about \$230 per ton of SOx removed at \$1.10 per barrel with desulfurization from 2.0% S to 0.5% S. As noted in Appendix D these costs are estimated manufacturing costs that may not reflect actual premiums, if any, paid to purchase these low sulfur fuels.

The cost effectiveness of implementing Rule 53.2 (LA County) in 1973 to restrict sulfur recovery plants to 500 ppm is evaluated in Appendix I. The total cost of installation of tail gas desulfurization processes was estimated at \$36 million for a total reduction of about 115 tons/day with an average cost effectiveness of about \$235 per ton SO<sub>2</sub> reduced. It would thus appear that Rule 53.2 was just about equally cost effective compared with Rule 62 fuel sulfur limitation.

Implementation of reduced unleaded gasoline sulfur content has the purpose of reduction in sulfuric acid mist reported to be emitted by cars with catalytic converters. In addition to acid mist elimination, there is of course a reduction in sulfur oxides. Current gasoline sulfur levels apparently average about 540 ppm and vary up to about 1000 ppm (parts of sulfur per million parts of gasoline by weight = 0.1% S by weight). As currently implemented at the state level, sulfur contents would be lowered to maximums of 500 ppm in 1976, 400 ppm in 1978, and 300 ppm in 1980. During the period while cars with converters installed remain a small portion of the vehicle population, these levels can most likely be achieved by blending with no added cost. As the vehicle population percentage of converter-equipped cars grows, this will become increasingly difficult to accomplish. Furthermore the ultimate sulfur goal may be as low as 100 ppm. To accomplish this the basin refineries are reported by the ARB to require investment of \$210 million for desulfurization equipment and gasoline prices would increase an estimate 2 cents per gallon (\$.84 per barrel). Using the standard cost effectiveness approach adopted for this program, the capital costs, amortized at 20%

per year plus 5% maintenance, and increased by 30% for operating costs, the effective annual cost is about \$68 million dollars. Total basin refinery capacity is 1 million barrels per day or about 330 million barrels per year of which about 45% or, correcting for specific weight difference, 190 million barrels per year, is gasoline. This corresponds to a daily gasoline consumption of 25 million gallons of which about 40% is consumed in Los Angeles County. The annual cost divided by gallons produced would indicate a manufacturing cost increase of about \$0.36 per barrel or about 1 cent per gallon. Added transportation and marketing costs would account for the reported 2 cents per gallon increase. For a reduction from 500 ppm to 100 ppm the total reduction (not all in the basin) would be about 60 tons of SOx as SO<sub>2</sub> per day or 20,000 tons per year. Dividing the \$68 million dollar annual cost increase by 20,000 tons/y results in a cost/benefit ratio of \$3,400 per ton of SOx as SO<sub>2</sub> reduced. At the 2 cents per gallon cost to the consumer this increases to \$8,000 per ton reduced. These figures could fluctuate widely based on the actual portion of the gasoline that must be desulfurized and the actual current average gasoline sulfur content (believed close to 500 ppm), but the general indication is that, with respect to total sulfur oxides reduction the desulfurization of unleaded gasoline is substantially more costly than the stationary source Rules 53 and 62 and SOx reductions are less.

The real purpose of the gasoline sulfur limit is to reduce acid mist emissions. Assuming that for converter-equipped cars the SO<sub>3</sub> is 30% by volume of the total 60 tons/day of SOx as SO<sub>2</sub> the reduction of acid mist would be 38 tons per day (60x0.3x134/64). By comparison implementation of Rule 53.2 for sulfur plants resulted in an estimated reduction of 0.5 tons/day of sulfuric acid mist. No data was available on effects of Rule 53.3 for sulfuric acid plants. A similar comparison for Rule 62

indicates that the reduction was 9 tons of acid per day. On the basis of the real intent of the gasoline sulfur limitation, rather than on total oxides of sulfur basis, the reductions in acid mist emissions are much greater as a result of gasoline sulfur limitations than for controls placed on stationary sources.

One note of caution must be mentioned. While vehicle emissions occur at ground level and exposure is immediate, stationary source SOx may travel far in the upper layers before reaching ground level. This could result in substantial additional conversion of stationary source SOx to acid mist than would be apparent from source tests within the stack. All comparisons of stationary and mobile source emissions must be tempered with the meteorological effects on each and the conclusions and comparisons drawn here with regard to emissions at the point of atmospheric entry must not be inappropriately interpreted in terms of air quality.

In summary, the cost/benefit ratio in terms of total sulfur oxides of Rules 53.2 and 62 was about \$235 and \$230 per ton respectively, compared with unleaded gasoline cost effectiveness of \$3,400 per ton. On the basis of sulfuric acid mist prevention the reductions achieved are much greater by limitation of gasoline sulfur content.

### 8.3 Fuel Type Selection As An Emissions Control Option

The extent of Basin-wide SOx emissions considered to be potentially reducible on a cost effective basis by direct control of specific sources is considered in the next section. A very basic point that must be first considered and the real cause of substantial increases forecast for the basin (Section 7.0) that being the curtailment of natural gas fuel for power plant consumption in the Basin. In discussing the 1974 inventory and the forecasts to 1975 and 1980 in Section 7 the dominant change resulting in sharply increasing SOx emissions is the decline of natural gas availability to the electric utilities. From over 80% of electric utility energy requirements being supplied by natural gas fuel in 1970, subsequent projected curtailment has reduced the natural gas availability to only 5% of utility requirements in 1975 and less beyond. This of course necessitates the shift to oil fuel.

At 1974 generation rates in the Basin the total energy output from the utilities was 42 million Mw-hr which corresponds to about 409 million million Btu energy requirement. Thus the emissions penalty being imposed on the Basin for burning all oil at 0.4% S average versus all gas is approximately 126 million pounds of SOx as SO<sub>2</sub> per year or 172 tons/day which is about 50% of stationary source emissions. At current prices the average oil cost to the electric utilities is about \$2.50 per million Btu vs about \$.50 per million Btu for gas. Thus in effect the Basin electric utilities are paying a premium of \$2.00 per million Btu for oil compared with gas if it were available. For the \$2.00 per million Btu premium the Basin is getting in return a net increase in SOx production of 0.30 lb SOx as SO<sub>2</sub> per million Btu, which means residents of the Basin are buying SOx at a cost of \$7 per pound.

This situation is the result of current Federal Power Commission gas allocations as discussed in Reference 1 regarding NOx and there is much current activity directed toward obtaining more natural gas for the basin. Control of the well-head price of natural gas is being maintained

supposedly for the benefit of the public. The resultant environmental impact of these decisions is apparently being disregarded or at least considered of lesser importance compared to economic and political influences and it is one purpose of the study reported here to provide further information to assist those active in the task of restoring basin natural gas requirements.

Recent events have indicated that the gas shortage in the basin may be short lived as supplies from Alaska and coal gasification become available, but may never be restored to utilities. Restoration of gas supplies to all interruptible users, without question, is the most cost effective means for control of sulfur oxides, and in addition all other known pollutants and this fact must be kept in mind when considering the potential reduction methods discussed in the next section.

#### 8.4 Summary Of Basin SOx Emission Reduction Potential

Potential opportunities for reducing the SOx emissions for each of the several categories of stationary emissions sources in the Basin have been assessed, and discussed in the respective appendices G-M. These potential reductions are summarized in Table 8-I. In compiling these reductions, control options were considered with cost/benefit ratios up to about \$2,000 of annual cost per ton of SOx as SO<sub>2</sub> reduced. There are only two control options now available, coke oven gas control and natural gas restoration, that provide as low a cost effectiveness as current controls on stationary sources SOx emissions. This is in contrast to a previous study of NOx reductions (Ref. 1) in which a number of potential reduction methods were defined that were more cost effective than the automotive NOx retrofit program. It is believed that the costs have been estimated conservatively high and the reductions conservatively low for the most part.

Reductions by fuel desulfurization are shown in the table as variable since no definitive criteria for SOx reductions needed were currently available, as discussed in Section 7.3. Reductions obtainable for other sources are more directly related to the reduction process and are indicated at fixed levels.

TABLE 8-I

SUMMARY OF POTENTIAL SO<sub>x</sub> EMISSIONS REDUCTIONS  
STATIONARY SOURCES, SOUTH COAST AIR BASIN

Source Category	# Units Reduced	1974 Annual Emissions tons/day	Estimated 1980 Annual Emissions tons/day	Projected Reduction 1980 Level tons/day	Primary Reduction Method	Estimated Average C/B Ratio \$/ton
*Utility Boilers	70	172	400-460	230-290	Restore Natural Gas	0
*Utility Boilers	70	172	400-460	220-280	Fuel Desulf. below 0.5% S	300-600**
*Utility Boilers	24	172	400-460	176	Scrubbers with 2% S oil	400-1350
Ind./Refin. Coml/Inst Boilers, Heaters	304 -938	19	41-95	20-50	Fuel Desulf. below 0.5% S	300-600**
Refinery FCC/CO Boilers	7	46	49	41	Refinery Venturi Scrubber	1144
Petroleum Coke kilns	5	26	26	15	Ionizing Wet Scrubber	600
Steel Mill Coke Oven Gas	27	23	23	18	Coke Oven Gas Sulfur Removal	122
Vapor Phase Reactors	7	5.4	5-16	5-16	Gas Plant, Claus Plant	312
Steel Mill Sinter Plants	2	4.4	4.4	3	Ionizing Wet Scrubber	470
Total Reduction at 1980 Level				274-433**		

\*Alternate Options

\*\*Fuel desulfurization reductions are a direct function of fuel sulfur level below 0.5% S. Maximum reductions are based on 0.2% S. This limit and the variation of C/B ratio between 0.5 and 0.2% S are discussed in Appendix F. Value ranges in 1980 emissions represent the new gas supply and no new gas supply cases.

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Because of the comparatively small numbers of devices and level of detail known on these devices, the reductions in several source categories were based on considerations of individual units. These categories included utility boilers, petroleum fluid catalytic cracking units, petroleum coke kilns, primary iron ore sintering, and coke ovens. With the device groups having large numbers in the oil refinery boiler and heater categories and industrial/commercial/institutional boiler categories it was necessary to estimate costs and reductions on an average overall basis rather than unit by unit.

As can be seen in Table 8-I the combined potential reduction in the Basin was found to be 274 to 433 tons per day with the range of reductions dependent on the degree of new natural gas supplies. The reductions achievable and costs involved are to a great extent dependent on the various options open to the utilities. Restoration of natural gas constitutes the single option of most importance. On the assumption that increased supplies will result in an increase in gas price to approximately equal the oil it replaces, the cost/benefit ratio is zero. One approach to increase utility gas supplies without increase of gas costs to residential consumers would be to deregulate only interruptible supplies over which the firm supply would have priority.

Should all efforts to restore natural gas fail and resultant ambient air quality deteriorations be positively related to stationary sources, the potentials reduction methods presented in Table 8-I would indicate that reduction can be achieved at cost/benefit ratio levels from \$122 to \$1350 per ton. The largest potential for total reduction is found in the further control of utility emissions. The total sum of all emissions from devices other than utilities is predicted to be 284 tons/day by 1980. Even if these sources were eliminated entirely there would still be an increase in emissions of 118 tons/day in 1980 relative to 1974. The combined total of estimated potentials for cost effective reduction of non-utility emissions is 102-143 tons/day.

Only one potential reduction method (coke oven-gas desulfurization) was identified that would be more cost effective than the \$230/ton value for Rule 62 limiting fuel sulfur to 0.5% or Rule 53.2 limiting sulfur scavenger plants to 500 ppm at a cost effectiveness of \$235/ton.

All assessment of reduction potential has been addressed to total sulfur oxides. Reduction of total sulfur oxides will result in a similar reduction of sulfur trioxide ( $\text{SO}_3$ ) in nearly direct proportion. In addition, as was shown in Figure 2-1, Section 2 of this report, the level of  $\text{SO}_3$  as a percent of  $\text{SO}_x$  is dependent on excess oxygen in combustion sources. Levels of  $\text{SO}_3$  remain relatively constant until stack gas oxygen is reduced below about 3% at which point the  $\text{SO}_3$  drops sharply. Implementation of low excess air for  $\text{NO}_x$  reduction was considered in Reference 1 and costs associated are given. As combustion source tests were not conducted during this program it is not possible to make practical estimates of the cost effectiveness for  $\text{SO}_3$  reduction by means of reducing excess oxygen in combustion devices. Furthermore it is believed that for stationary sources with relatively high stacks that, except for localized acid mist or acid particulate fallout, much more sulfuric acid and sulfate particulate is formed in the atmosphere from additional post stack oxidation of the  $\text{SO}_2$  portion of total sulfur oxides. Therefore it is believed that specific controls or regulations to limit  $\text{SO}_3$  emissions at the stack exit would be largely ineffective and a more direct approach is through control of total sulfur oxides. These conclusions would not apply to ground level sources such as automobiles where emissions are immediately respirable.

One additional problem that relates to control of sulfur trioxide ( $\text{SO}_3$ ) at the source concerns the fact that currently available methods for measurement of  $\text{SO}_3$  involve a high uncertainty and lack adequate methods of calibration. Further investigation would be necessary to resolve these problems before any consideration could be given to regulatory controls of  $\text{SO}_3$ .



## 9.0 SUMMARY - CONCLUSIONS

A comprehensive inventory of oxides of sulfur emissions has been compiled for stationary sources in the South Coast Air Basin for 1974. The inventory is based on detailed device design and fuel use information on 1583 sources provided in a similar recent study of oxides of nitrogen, updated to 1974 and supplemented with additional information specific to oxides of sulfur. The emissions were determined from the combined use of established fuel related emission factors and sulfur contents, of specific test data available from the operators or APCD files, and of the results of 38 device emissions tests conducted during the program.

The year 1974 was somewhat unusual in that large amounts of hydroelectric power were imported resulting in 22% lower sulfur oxides emissions on an annual basis compared with the previous year. As a result of this there was no comparable estimate of emissions for the total basin with which to compare. However on the basis of specific device comparisons it is believed that the current understanding of sulfur oxides emissions is consistent with the results of this report.

The most significant result of the inventory relates to the sharp increases experienced in the average 1974 summer emissions of sulfur oxides. While overall 1974 sulfur oxides emissions were down from 1973, the shortage of natural gas has begun to be realized in summer time curtailments of gas use. From only 5% oil use in 1972-1973 period during August, the electric utilities were required to supply 50% of their fuel as low sulfur oil during August of 1974. This increase in summer oil use will result in substantial increases in sulfur oxides emissions during peak smog periods. Summer emissions have recently been decreased by stringent controls on sulfur scavenger and sulfuric acid plants that would have resulted in only about 160 tons/day in August, 1974 had the utilities been able to burn gas. As a result of increased oil use August 1974 emissions were found to be 305 tons/day.

In the most likely event that these trends continue, annual sulfur oxides emissions from stationary sources will grow from an average of 342 tons/day in 1974 to an estimated 743 tons per day in 1980, assuming the low sulfur fuel oil can continue to be found to replace the curtailed gas. If the basin is also denied even this fuel, requiring the use of fuels in excess of 0.5% S, sulfur oxide emissions could well grow to over 1000 tons/day. Summer average emissions will rapidly rise to a level nearly equal the annual emissions. These increases will occur not only from utility boilers but also a wide variety of industrial fuel burning equipment.

Sulfur oxides are emitted from two broad groups of activity: combustion of fuels and the processing of sulfur-bearing materials. The first group is dominated by the electric utility power plants. Other combustion sources include the refinery gas and oil burned in basin oil refineries, and a wide variety of industrial, commercial, and institutional boilers. Domestic natural gas use is a very minor source. Plants processing sulfur-bearing materials that emit sulfur oxides include oil refineries, carbon plants, sulfur plants, sulfuric acid plants, glass and aggregate mineral plants. On an industry basis the electric utilities contributed 50% of 1974 annual sulfur oxides emissions, followed by the petroleum industry (27%), carbon plants (7%), and metals (13%). The remaining 3% is emitted by chemical and mineral plants, and by various other industrial, commercial and institutional devices, primarily boilers.

The distinct seasonal nature of sulfur oxides emissions resulted in 1974 summer emissions 11% lower, and winter emissions 36% higher, compared with annual averages that are normally used to express basin emissions.

The emissions, distributed on a 10 km (6.2 mi) square grid system, were found to be highly concentrated in near coastal south-west Los Angeles County where 61% of the total annual emissions came from just 5 grid squares in an area of high concentration of power plants and industrial facilities.

A forecast was made of the total stationary source emissions in the basin that indicated a 52% growth from 1974 to 1976 and a 14-39% growth from 1976 to 1980 dependent on gas supply. As noted, 1974 emissions were reduced and were found to be about equal to those in 1970 which was a previous minimum with a peak occurring in 1973. The overall projected growth from the 1970 low to 1980 is 67-100% or a 5.3-7.3% average annual growth rate dependent on gas supply.

In contrast with most other pollutants, sulfur oxides is emitted primarily from stationary sources (82%), with only 18% coming from mobile sources. Combining mobile and stationary sources, total basin sulfur oxides emissions were about 420 tons/day in 1974 with growth to about between 680 and 840 tons/day in 1980 dependent on the availability of new gas supplies.

Oxides of sulfur are composed of sulfur dioxide ( $\text{SO}_2$ ) and sulfur trioxide ( $\text{SO}_3$ ). Sulfur trioxide, in the presence of moisture, forms sulfuric acid mist. Recent concern has been expressed regarding sulfuric acid mist emissions from vehicles equipped with catalytic converters. Stationary sources also emit small amounts of the total sulfur oxides as sulfur trioxide or acid mist and estimates of these emissions were made in this program. In 1974 the  $\text{SO}_3$  rate was estimated at about 13 tons per day or about 3.0% of total sulfur oxides on a volumetric basis. (This emission rate of  $\text{SO}_3$  would produce 22 tons/day of sulfuric acid mist.) Utility power plants are, as with total sulfur oxides, the major source. Mobile sources are presently much lower in sulfur trioxide emissions, emitting sulfur trioxide equivalent to an approximate 4 tons per day of sulfuric acid mist. Although specific data on sulfuric acid formation from catalytic converters was not available, a rough estimate indicates possible growth to between 20 and 30 tons per day when the basin vehicles are mostly all using converters. By 1980 stationary source emissions the sulfuric acid equivalent of sulfur trioxide will grow to about 45 tons/day. Therefore while mobile sources are currently a small percentage of all sulfur oxides compounds, and will continue to be so for sulfur dioxide, the mobile emissions of

sulfuric acid mist may grow to nearly equal those from stationary sources although this would probably not occur until sometime after 1980.

Detailed considerations of the influence of current and projected SOx emissions on air quality were beyond the scope and resources of the current program. However, a brief review was made of the current air quality status with regard to standards for gaseous SO<sub>2</sub>, particulate matter, and visibility. With the exception of 51 days in Los Angeles County on which the state standard of 0.04 ppm, 24 hour average for SO<sub>2</sub> concentration was exceeded, all current standards were met in 1974. Attention should be given to the possibility that projected increases in SOx emissions will result in the SO<sub>2</sub> standards being exceeded more frequently. The situation with regard to particulate matter and visibility is apparently more complex and most low level air quality standards are exceeded to a much more frequent degree than for SO<sub>2</sub>. The emissions of SOx are partially responsible for this situation through atmospheric conversion of gaseous SO<sub>2</sub> to acid mist and sulfate particulates. Therefore control of SOx is an important part of an overall program to achieve the air quality standards. Because of the complexity of these air quality problems it was not possible with the resources of this program to provide definitive criteria for SOx controls as relate to stationary source control requirements but the results of this program will be an important input to that definition.

An examination of each of the stationary source categories was made to determine potentials for reduction of sulfur oxides emissions. It was found that the most cost effective reduction methods have already been implemented and that, while very efficient control methods are available, most future reductions will be increasingly more costly.

The projected growth in basin sulfur oxides emissions comes almost entirely from the curtailment of natural gas and restoration of that gas represents the most cost effective method for sulfur oxides reductions. All stationary sources are currently operating under some form of sulfur oxides regulations and with a very few isolated exceptions, related to control maladjustment, all sources tested were complying with these regulations. While several reasonably cost effective methods of sulfur

oxides potential reductions were identified, the time period required for installation would bring them on line about the time projected new sources of natural gas for the basin may become available and possibly render these controls unnecessary. It would therefore be inappropriate to interpret the potential reduction methods presented as recommended reduction methods. The primary effort for air quality maintenance should be directed toward restoration of natural gas supplies. In the event that adequate supplies of natural gas to serve utility needs cannot be restored, consideration of further regulatory controls on stationary source emissions of sulfur oxides may be necessary to achieve air quality standards. These comments have implications for most other pollutants as well.

As the projected growth in sulfur oxides emissions is the direct result of projected increases in fuel oil use, any effort to restrict that growth will effect SOx growth limitation. In addition to increased gas supplies, improvements in operating efficiency and procurement of power from outside the basin are alternate objectives that would serve the same objective.

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COMPUTATION METHODS

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## APPENDIX A

### COMPUTATION METHODS

#### A-1.0 POINT SOURCES - COMBUSTION OF FUEL

For devices where the combustion of fuel is the only source of SO<sub>x</sub>, where no materials are involved that would absorb SO<sub>x</sub>, and where no exhaust gas treatment units are employed, the emissions of SO<sub>x</sub> are estimated directly from the fuel use and fuel sulfur content. Table A-I presents several formulae for conversion of fuel sulfur content to emission factors for the various measures employed in fuel use assuming 100% conversion of sulfur to SO<sub>x</sub> emissions.

For plants where fuel properties are reported to county agencies or data were available from company records, these properties were used for emission factor computation. For fuel use where properties were not available, the typical values were assumed as listed in Table A-II.

Summer and winter daily average emission rates are calculated as

$$E_{XDS} = (F_{XG} W_{DSG} + F_{XO} W_{DSO}) / 2000 \quad (A-1)$$

and

$$E_{XDW} = (F_{XO} W_{DWO} + F_{XG} W_{DWG}) / 2000 \quad (A-2)$$

where:

- $E_{XDS}$  = SO<sub>x</sub> summer average daily rate, tons as SO<sub>2</sub>/day
- $E_{XDW}$  = SO<sub>x</sub> winter average daily rate, tons as SO<sub>2</sub>/day
- $F_{XG}$  = gas fuel emission factor, lb SO<sub>2</sub>/MMCF
- $F_{XO}$  = oil fuel emission factor, lb SO<sub>2</sub>/M gal
- $W_{DSG}$  = daily summer gas use, MMCF/day
- $W_{DWO}$  = daily winter oil use, M gal/day
- $W_{DSO}$  = daily summer oil use, M gal/day
- $W_{DWG}$  = daily winter gas use, MMCF/day

For devices that do not burn gas, both summer and winter emissions are based on oil and for devices that do not burn oil, the emissions are based on gas. Values of  $F_{XG}$  and  $F_{XO}$  are obtained from the emission factor table.

TABLE A-I

SO<sub>x</sub> EMISSION FACTORS FOR COMBUSTION OF FUEL  
WITH 100% CONVERSION OF SULFUR TO SO<sub>x</sub>

<u>OIL FUELS</u>	
$\frac{\text{lb SO}_2}{\text{lb fuel}} = \frac{(\% \text{ S})}{50}$	
$* \frac{\text{lb SO}_2}{\text{M gal}} = 167 (\% \text{ S}) (\text{s.g.})$	
$\frac{\text{lb SO}_2}{\text{BBL}} = 7 (\% \text{ S}) (\text{s.g.})$	
$\frac{\text{lb SO}_2}{\text{MMBtu}} = \frac{20000 (\% \text{ S})}{(\text{HHV, Btu/lb})} = \begin{cases} 1.05 (\% \text{ S}) \text{ for residual oil} \\ 1.00 (\% \text{ S}) \text{ for distillate oil} \end{cases}$	
<u>GAS FUELS</u>	
$* \frac{\text{lb SO}_2}{\text{MMCF}} = 2.69 \left( \frac{\text{Grains H}_2\text{S}}{100 \text{ CF}} \right) = 1500 (\% \text{ S}) (\text{s.g.})$	
$\frac{\text{lb SO}_2}{\text{Equiv. BBL}} = \frac{(\text{Grains H}_2\text{S}/100 \text{ CF})}{61.98}$	Note: use 82.64 for refinery gas in place of 61.98 for lb SO <sub>2</sub> /Equiv. BBL
$\frac{\text{lb SO}_2}{\text{MMBtu}} = \frac{2.69 (\text{Grains H}_2\text{S}/100 \text{ CF})}{(\text{HHV, Btu/CF})} = \frac{(\text{Grains H}_2\text{S}/100 \text{ CF})}{390.5} \text{ at } 1050 \text{ Btu/CF}$	

Notes: % S = percent sulfur by weight in fuel  
(1 pound of S = 2 pounds of SO<sub>2</sub>)

s.g. = oil fuel specific gravity relative to water at 60°F  
(8.328 pounds/gallon), s.g. = 141.5/(131.5 + °API)  
(gas fuel specific gravity relative to air at 0.075 lb/ft<sup>3</sup>)

Mgal = 1000 gallons

BBL = barrels (42 gallons)

MMBtu = million British thermal units

MMCF = million cubic feet

Equiv. BBL = gas fuel equivalent barrels on Btu basis (approximately 6000 CF of natural gas fuel at 1050 Btu/CF, or 4500 CF for refinery gas at 1400 Btu/CF)

HHV = fuel higher heat value, Btu/lb (oil) or Btu/CF (gas)

\*Denotes emission factors used by EPA and in current program.



TABLE A-II

TYPICAL FUEL SULFUR CONTENT, SPECIFIC  
GRAVITY AND SO<sub>x</sub> EMISSION FACTORS

Fuel	SO <sub>x</sub> Data Base Fuel Code	% Sulfur by Weight	Specific Gravity	SO <sub>x</sub> Emission Factor
Natural gas	NG	0.00093	0.6	0.84
Refinery gas	RG	0.02	0.8	24.00
Process gas	PG	0.01	0.6	9.00
Liquid petroleum gas	PO	0.0	1.5	0.00
Gasoline	GO	0.05	0.70	5.83
Diesel oil	LO	0.25	0.84	34.95
Jet fuel	JO	0.05	0.84	6.99
Distillate oil	DO	0.25	0.84	34.95
Residual oil	RO	0.40	0.91	60.62
Crude oil	CO	0.40	0.91	60.62
Coke	CS	0.60	-	24.00
Coke oven gas	CG	0.90	0.44	592.00

## Notes:

- Specific gravity of gas fuels is relative to air, and for liquid fuels relative to water.
- Units of emission factor for gas fuels are lb SO<sub>2</sub>/MMCF, for liquid fuels are lb SO<sub>2</sub>/M gal, for solid fuel lb SO<sub>2</sub>/ton.
- Sulfur percent for gas fuels based on:

Natural gas = 0.31 grains H<sub>2</sub>S/100 CF (5 ppm)

Refinery gas = 6.3 grains H<sub>2</sub>S/100 CF (100 ppm)

Process gas = 3.3 grains H<sub>2</sub>S/100 CF (53 ppm)

Coke oven gas = 220 grains H<sub>2</sub>S/100 CF (3520 ppm)

For gas fuels

$$\frac{\text{grains H}_2\text{S}}{100 \text{ CF}} = \frac{\text{ppm (volume)}}{16}$$

In recent years, it was common for many devices to burn only gas in the summer and only oil in the winter. For a previous study of NOx emissions conducted by KVB for the period July 1972 - June 1973 (Ref. 1), it was assumed that all devices capable of burning gas were in fact burning gas in the summer. Conversely, all devices capable of burning oil were assumed to do so in the winter. Computations for the preliminary inventory of SOx for this program (Appendix C) retained these assumptions. However, review of the fuel use patterns for 1974 particularly for the utilities and oil refinery devices indicated that the shortage of natural gas has resulted in substantial increases of oil use in the summer increasing from 95/5% typical gas/oil split in the 72-73 period to about a 50/50 split in 1974. This shift in fuel use has been taken into account by allowing for both oil and gas use in the summer and winter SOx computations by Equations A-1 and A-2.

The annual average daily emissions are computed from total annual fuel use by

$$E_{XA} = \frac{F_{XG} W_{AG} + F_{XO} W_{AO}}{(2000) (365)} \quad (A-3)$$

where  $E_{XA}$  = SOx annual average, tons as SO<sub>2</sub>/day

$W_{AG}$  = annual gas use, MMCF/year

$W_{AO}$  = annual oil use, M gal/year

Where fuel sulfur content data show significant monthly variations, the gas and oil emissions can be calculated for each month and summed for the average.

Fuel usage for each device is obtained by several methods dependent on the type of information available. Response to a questionnaire sent for the NOx study (Ref. 1) provided summer, winter and annual fuel use on about 500 industrial devices for the inventory period of July 1972 to June 1973. For those devices the fuel use is taken directly. For other devices such as refinery boilers and heaters and utility boilers the fuel usage is known only for the total plant or generating station. In these cases fuel is apportioned to each device on the basis

of rated heat input as a percent of total plant rated heat input. Where capacity factors are available the fuel distribution is adjusted to reflect relative capacity fractions. For the preliminary inventory fuel usages determined in the NOx study for the 72-73 period were retained. Adjustment to the 1974 inventory period was made for the final inventory.

For devices that burn both gas and oil, it is important to understand the assumptions made in computing the summer and winter daily fuel use. On any specific day a given device may burn all oil, all gas, operate part of the day on gas and the rest on oil, or use both simultaneously. Information on these patterns is rarely available and frequently the total fuel use is known only for a group of devices some of which may operate on gas and others on oil. Resolution of these effects is not critical since the emissions of SOx are related solely to the amount of fuel burned and are not device dependent as are emissions of other pollutants such as NOx. Furthermore, the changing patterns of fuel use make it no longer possible to specify a "typical" summer or winter fuel for 1974. Therefore, to establish summer and winter fuel rates, the total fuel used for the months of August and December are determined and the fraction of oil burned on an energy release basis is determined. This fraction is used to apportion part of the daily average energy consumption to oil use and the remaining to gas use. The daily emission rates of SOx are then essentially an average based on one month's operation. On any given day the actual SOx emissions could be higher or lower depending on the actual daily fuel use patterns. For example, a boiler operating with a 50/50 gas/oil total consumption during August would emit about twice the daily average SOx emissions on those days when all oil is burned. However, only during the occurrence of a wide spread basin curtailment of natural gas would all oil burning devices actual burn oil. The use of a monthly average oil use fraction is therefore believed to result in a more realistic basin wide SOx emission rate.

In accordance with the foregoing assumption, the daily uses of oil and gas are computed in the following manner:

$$W_{DSG} = \frac{Q T_S C_{FS}}{H_G} (1 - S_{SO}) \quad (A-4)$$

$$W_{DSO} = \frac{Q T_S C_{FS}}{H_O} (S_{SO})$$

$$W_{DWG} = \frac{Q T_W C_{FW}}{H_G} (1 - S_{WO}) \quad (A-6)$$

$$W_{DWO} = \frac{Q T_W C_{FW}}{H_O} (S_{WO}) \quad (A-7)$$

$$S_{SO} = \frac{\text{Barrels of oil used in August}}{\text{Total equivalent barrels of all fuel used in August}} \quad (A-8)$$

$$S_{WO} = \frac{\text{Barrels of oil used in December}}{\text{Total equivalent barrels of all fuel used in Dec.}} \quad (A-9)$$

where:  $Q$  = heat input rate, MMB/h  
 $T_S$  = summer daily operating time, h  
 $T_W$  = winter daily operating time, h  
 $C_{FS}$  = summer capacity factor  
 $C_{FW}$  = winter capacity factor  
 $H_G$  = gas fuel heating value, MMB/MMCF  
 $H_O$  = oil fuel heating value, MMB/M gal  
 $S_{SO}$  = fraction of energy as oil in August  
 $S_{WO}$  = fraction of energy as oil in December

The foregoing computations result in the estimated total SOx emissions. The predominant SOx compound emitted is sulfur dioxide (SO<sub>2</sub>) with a small amount of sulfur trioxide (SO<sub>3</sub>). The SO<sub>3</sub> may be converted to sulfuric acid (H<sub>2</sub>SO<sub>4</sub>) in the presence of moisture and low temperature. Tests of combustion devices (Ref. 3) operating on oil fuel indicate that SO<sub>3</sub> content varies from less than 1% up to 13% of the total SOx on a volume basis. For low sulfur oils at 0.3 to 0.5% sulfur the data indicate an SO<sub>3</sub> content of 2 to 4% with an average of 3%. Accordingly, where

specific data were not available, a value of 3% was selected for use in distributing the inventory SOx emissions between SO<sub>2</sub> and SO<sub>3</sub>. Summer, winter and annual averages of SOx and SO<sub>3</sub> are computed on this basis. The SOx values are presented directly as SO<sub>2</sub> with a molecular weight of 64. Since SO<sub>3</sub> ultimately reacts with water to form sulfuric acid in the stack or atmosphere, many agencies compute SO<sub>3</sub> emissions as a liquid aerosol particulate on the basis of H<sub>2</sub>SO<sub>4</sub> (molecular weight of 98) or 2H<sub>2</sub>O.H<sub>2</sub>SO<sub>4</sub> (molecular weight of 134). For the current inventory the SO<sub>3</sub> emissions are presented directly as SO<sub>3</sub> (molecular weight of 80) and conversion to another desired chemical form can be made by the ratio of molecular weights.

#### A-1.1 Point Sources - Material Processing

For devices that process sulfur-bearing materials the emissions of SOx are obtained from an emission factor that relates the quantity of SOx emitted to the amount of material processed. The quantity of material processed is required for the summer, winter and annual emission rates. The seasonal variation in processing devices is not as predominant as in the fuel combustion devices and in many cases the three rates are expected to be the same. However, for completeness the three values were retained for the inventory.

The summer and winter daily SOx emission rates are computed from

$$E_{XDS} = \frac{F_{XP} R T_S C_{FS}}{2000} \quad (A-10)$$

and

$$E_{XDW} = \frac{F_{XP} R T_W C_{FW}}{2000} \quad (A-11)$$

where:

- $E_{XDS}$  = SOx daily summer rate, tons as SO<sub>2</sub>/day
- $E_{XDW}$  = SOx daily winter rate, tons as SO<sub>2</sub>/day
- $F_{XP}$  = SOx emission factor, lb SO<sub>2</sub>/ton of material
- $R$  = rated material use, tons/hr
- $T_S$  = summer daily operating time, hours

$T_W$  = winter daily operating time, hours  
 $C_{FS}$  = summer fraction of rated capacity  
 $C_{FW}$  = winter fraction of rated capacity

The summer and winter capacity factors are determined by

$$C_F = \frac{\text{Tons processed per month}}{(\text{Max ton rating/hr}) (\text{operating hours/month})} \quad (\text{A-12})$$

These capacity factors are, therefore, an average based on summer and winter monthly material use and are the relative capacity while operating. For the preliminary inventory capacity factors were assumed to be 0.8 for both summer and winter and 24-hour-per-day operation is assumed for the full month. These assumptions were revised for the final inventory based on information gathered from device operators.

The annual SOx emission rate is computed from

$$E_{XA} = \frac{F_{XP} W_A}{(2000) (365)} \quad (\text{A-13})$$

where:  $E_{XA}$  = SOx annual daily average, tons/day  
 $W_A$  = total annual material use, tons/year

For the preliminary inventory the total annual material use was taken, where available, from a previous survey conducted for the EPA (Refs. 22, 23). For devices not included in that survey the material use was estimated based on an 0.8 capacity factor and full year operation at 24 hours per day. These preliminary estimates were revised based on information obtained from the device operators for the final inventory.

Emission factors used in the foregoing equations were obtained from EPA tabulations (Ref. 19) or were derived from APCD test data. Revisions were made as necessary for the final inventory based on the source tests conducted in this program as discussed in the separate device appendices in this report.

Computation of the separate SO<sub>2</sub> and SO<sub>3</sub> emissions were made based on the measured volume fraction of SO<sub>3</sub> as determined in the

test program. For devices not tested, average values typical of other similar devices were assumed.

#### A-1.2 Area Sources

Large numbers of small domestic, commercial, institutional, and industrial combustion devices are distributed over the basin. The majority of these devices operate only on natural gas fuel. An accounting of fuel distribution by population, income, area and commercial and industrial activity was performed in the previous ARB study of NOx emissions (Ref. 1). For a typical natural gas sulfur content of 0.3 grains  $H_2S$ /100 cubic feet the total annual SOx emission from these sources is 166 tons  $SO_2$ /year or 0.45 tons/day average. In the previous study these sources were distributed on the basis of 10 km grids. For the grid with the highest fuel usage the SOx emission is 5 tons  $SO_2$ /year or 0.014 tons/day.

Compared with the point source emissions, these emissions from natural gas are negligible and thus are not included in the geographical inventory.

## REFERENCES

1. Bartz, D. R., et al., "Control of Oxides of Nitrogen from Stationary Sources in the South Coast Air Basin of California," KVB Engineering, ARB-R-2-1471-74-31, PB-237688/7WP, Sept. 1974.
3. Cato, G. A., et al., "Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers, Phase I," KVB Engineering, EPA/650/2-74-078-a, PB-238 920/3WP, Oct. 1974.
19. "Compilation of Air Pollutant Emission Factors," Office of Air Programs Publication No. AP-42, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, February 1972.
22. "Point Source Emission Inventory for Los Angeles County" EPA, Basic Ordering Agreement 68-02-1004, Task 2; Pacific Environmental Services, R. W. Bryan, February 1974.
23. "Point Source Emission Inventory for California - Excluding Los Angeles County," EPA Basic Ordering Agreement 68-02-1004, Task 1; Pacific Environmental Services, A. Stein, February 1974.



APPENDIX B

## INVENTORY DATA FORMAT AND PROCESSING

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## APPENDIX B

### INVENTORY DATA FORMAT AND PROCESSING

At the request of the ARB, the SOx point source inventory data record format is that of the Environmental Protection Agency's National Environmental Data System (NEDS). The description of this data recording system is found in Reference 18, EPA "Guide for Compiling a Comprehensive Emissions Inventory." A reproduction of the EPA's NEDS point source input is presented in Figure B-1.

#### B-1.0 PHYSICAL DESCRIPTION

The SOx data base as it currently exists is made up of approximately 1600 data records in NEDS format. Each record describes a specific point source located within the South Coast Air Basin. An exception was made for certain sources which are made up of a number of identical devices (such as turbines or IC engines) normally operated together and sometimes sharing a common stack. The number of such devices comprising the source is noted in the record. The records are each organized into fifteen 80-column card images. At present, over 150 specific data items have been defined to describe each record. Space has been left within each record to accommodate the definition of additional data items as the need arises.

A general description of the type of information found on each card is as follows:

<u>NEDS</u> <u>Card</u>	<u>Data Base</u> <u>Record Number</u>	<u>Information</u>
0	1	Record leader card - identifies inventory data record
1	2	Company name and location
2	3	UTM coordinates (UTM = Universal Transverse Mercator)
3	4	Design capacity and control equipment data
4	5	Plant operating schedule and emissions data
5	6	Compliance information
6A	7	Fuel use or processed material use
6B	8	Fuel use
6C	14	Fuel use (Note: Card 6C follows card A)
6D	15	Fuel use (Note: Card 6D follows cards A and 6C)

# POINT SOURCE Input Form

State	County	AQCR	Plant ID
1 2 3 4 5 6 7 8 9 10 11 12 13			

Name of Person  
Completing Form \_\_\_\_\_

Date \_\_\_\_\_

City		UTM COORDINATES		Establishment Name and Address		STACK DATA		Contact - Personal		Action	
Point ID	Year of Record	UTM Zone	UTM Horizontal km	UTM Vertical km	Height (ft)	Diam (ft)	Temp (°F)	Flow Rate (ft³/min)	Plume Height If no stack H	CD	Action
14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80											

Boiler Design		CONTROL EQUIPMENT		ESTIMATED CONTROL EFFICIENCY (%)	
Year of Record	Capacity (MMBtu/hr)	Primary	Secondary	Primary	Secondary
16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80		Part.	Part.	NO <sub>x</sub>	CO

% ANNUAL THROUGHPUT		EMISSION ESTIMATES (tons/year)	
Year of Record	Operating	SO <sub>2</sub>	NO <sub>x</sub>
16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80			

ALLOWABLE EMISSIONS (tons/year)		CONTROL REGULATIONS	
Year of Record	SO <sub>2</sub>	Reg 1	Reg 2
16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80			

FUEL PROCESS, Solid Waste		Comments	
Year of Record	Operating Rate	Heat Content (10 <sup>6</sup> BTU/sec)	Source
16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52 53 54 55 56 57 58 59 60 61 62 63 64 65 66 67 68 69 70 71 72 73 74 75 76 77 78 79 80			

FIGURE B-1. EPA NEDS POINT SOURCE CODING FORM.

<u>NEDS</u> <u>Card</u>	<u>Data Base</u> <u>Record Number</u>	<u>Information</u>
7	9	Present NOx emissions status
8	10	Summer/winter capacity and usage factors for gas and oil and NOx emission data
9	11	Present SOx emissions status and data
A	12	Unused card for future additions
B	13	Unused card for future additions

Because of the limited scope of the present inventory, i.e., SOx only, certain of the NEDS card fields have not been used as indicated by the shaded areas in the version of the form used for this program, Figure B-2. Although not shaded, stack data on card 2 was not entered in the data base. However, to fully utilize available card space, additional information such as APCD permit number and state industrial safety permit number have been added into previously blank fields. The NEDS Variable Data Input Form<sup>(18)</sup> is used to record more detail on device use and emissions rates. Figure B-3 shows the data input form. Symbols used to identify card field are defined in Section 5.0, Computation Methods.

The NEDS forms for the initial version of each source are on file. This data has been transferred to magnetic disk for processing via a Datapoint 2200 digital computer. All subsequent modifications to the original data are made directly on the disk.

The SOx data base is stored on disk in an indexed sequential manner. That is, a fifteen character key identifies each data record. To ensure uniqueness of the keys, each is composed of coded numbers for the following five data items: state, county, AQCR (Air Quality Control Region, 24 for the South Coast Air Basin), plant ID, and point ID. This key occupies the first fifteen columns of each card image within a data record.

NATIONAL EMISSIONS DATA SYSTEM (NEDS)  
CALIFORNIA AIR RESOURCES BOARD  
SOX SURVEY CONTRACT #4-421

POINT SOURCE  
INPUT FORM

[illegible]

FIGURE B-2. MODIFIED NEDS FORM FOR ARB SOX INVENTORY.

# VARIABLE DATA INPUT FORM

DATE \_\_\_\_\_  
NAME OF PERSON \_\_\_\_\_  
COMPLETING FORM \_\_\_\_\_

PRESENT NOx EMISSIONS STATUS

PRESENT NOX EMISSIONS STATUS (CONT.)

PRESENT SO<sub>x</sub> EMISSIONS STATUS

[illegible]

5802-432

#### B-1.1 Maintenance and Preservation

Two modes of operation are used in connection with the data base. The most important function is that of providing information from which reports are written. To do this, data must be extracted from the total data base and processed (sorted, summed, etc.) to produce the desired reports. The actual report writing is accomplished through the use of a higher level programming language available on the DATAPOINT 2200 computer.

The second mode of operation is that of maintenance and includes additions, deletions, and modifications to the entire data base. This is carried on in support to both the field testing program and acquiring data from other sources. New data is assimilated into the data base as it is acquired, thus providing the most up-to-date data from which to write reports.

It is most important to preserve the integrity of the data base. Great care is taken to insure that the data base is not destroyed. This is accomplished through a multi-step procedure. First, logical milestones are established throughout the data acquisition phase. At these milestones, a dated listing of the entire data base is printed. Next, an exact copy of the existing data base is written to a second disk. A checking procedure is then employed to validate the copy. Only the primary version of the data base is used when updating the data and writing reports. The back up version would only be used to recreate the data base in the advent of a computer malfunction. Procedures are also employed to ensure that no data is added, deleted, or modified unless duly authorized and recorded.

#### B-1.2 Inventory Report Processing

In summarizing the data for the inventory, summations are made on three bases, type of device, category of application, and geographical location. The device type sort is made on the NEDS source classification code (SCC code, NEDS card 6, columns 18 through 25). A summary of the more significant device categories and their respective SCC codes is presented



in Table B-1. While the SCC code also contains information on device application it was found that this code was not satisfactory for many common heat transfer devices such as boilers and heaters since the application category is not specifically defined for these devices. Hence to make it possible to sort in terms of applications categories similar to those used by the APCD's, an application (or device user) category classification was devised and was recorded in column 73-76 of card 6A. A summary of the more significant application categories is presented in Table B-2. The geographical sort was made on the basis of the 10 Km grid system adopted which is defined by the even 10,000 meter lines of the UTM coordinate system. Devices originally located by the LAC APCD data file were located on a 1 mile grid system and were subsequently transferred to the UTM grid system to an accuracy of  $\pm 1/2$  mile.

Reports in other forms can be easily prepared to format or sort data base information in any desired manner.

#### REFERENCES

18. "Guide for Compiling a Comprehensive Emissions Inventory," APTD-1135, Environmental Protection Agency, February 1972.

TABLE B-I

SOURCE CLASSIFICATION CODE (SCC)  
ARB SOx INVENTORY BY DEVICE TYPE

	I	II	III	IV	UNITS
<u>BOILERS</u>	1				
Electric		01			
Industrial		02			
Commercial/Institutional		03			
Resid. Oil			004		M gal
Dist. Oil			005		M gal
Nat. Gas			006		MMCF
Refin. Gas			007		MMCF
<u>I.C. ENGINES</u>	2				
Electric Turbine		01		01	
Industrial Turbine		02		01	
Dist. Oil			001		M gal
Nat. Gas			002		MMCF
Industrial Reciprocating, Nat. Gas		02	002	02	MMCF
Commercial/Institutional Reciprocating		03	XXX	XX	
Industrial Jet Engine Test		04	001	01	M gal
<u>INDUSTRIAL PROCESS</u>	3				
Chemical		01			
Sulfuric Acid			023	XX	Tons Acid
Sulfur Recovery			032	XX	Tons Sulfur
Miscellaneous			XXX	XX	
Food/Agricultural		02	XXX	XX	
Primary Metals		03			
Aluminum			001	XX	Tons AL
Iron			008	XX	Tons
Steel			009	XX	Tons
Lead			010	XX	Tons ore/prod
Other			XXX	XX	Tons
Secondary Metals		04			
Aluminum			001	XX	Tons
Grey Iron			003	XX	Tons
Lead			004	XX	Tons
Steel			007	XX	Tons
Other			XXX	XX	Tons
Mineral Products		05			
Asphaltic Concrete			002	XX	Tons prod
Cement			006	XX	Tons
Ceramic/Clay			008	XX	Tons
Glass			014	XX	Tons glass
Gypsum			015	XX	Tons
Mineral Wool			017	XX	Tons
Miscellaneous			XXX	XX	Tons
Petroleum		06			
Process Heater			001		
Oil				03	M gal
Gas				04	MMCF
Fluid Catalytic Cracking			002	01	M bbl
Metal Fabrication		09	XXX	XX	Tons
Textile		30	XXX	XX	Tons
Industrial In-Process Fuel		90			
Residual Oil			004		M gal
Dist. Oil			005		M gal
Nat. Gas			006		MMCF
Process Gas			007		MMCF
Coke			008		Tons
LPG			010	XX	M gal
Other (propane)			999	98	M gal
<u>SOLID WASTE</u>	5				
Government		01	XXX	XX	Tons
Coml/Inst.		02	XXX	XX	Tons
Industrial		03	XXX	XX	Tons

TABLE B-II.

APPLICATION CATEGORY CLASSIFICATION01 - UTILITY

- 01 - Gas turbine - electric generation
- 02 - Steam boiler " "
- 03 - Other IC device " "
- 04 - IC devices - natural gas transmission
- 05 - Standby electric generation - telephone

02 - INDUSTRIAL - CHEMICAL & RELATED INDUSTRIES

- 01 - Agricultural chemicals and fertilizers
- 02 - Intermediates, plastics, resins, rubber, adhesives
- 03 - Paints, coatings, etc.
- 04 - Pharmaceuticals and cosmetics
- 05 - Unclassified
- 06 - Sulfuric acid

03 - INDUSTRIAL - MANUFACTURING, MAINTENANCE, AND ASSEMBLY

- 01 - Heavy (metal fabrication, forging, etc.)
- 02 - Medium (auto and aircraft assembly, maintenance)
- 03 - Light (toy, electronics, textiles)
- 04 - Unclassified

04 - INDUSTRIAL - METALLURGICAL

- 01 - Iron and steel production
- 02 - Aluminum production
- 03 - Other metal production, melting

05 - INDUSTRIAL - MINERAL INDUSTRIES

- 01 - Asphalt paving
- 02 - Cement and concrete
- 03 - Glass
- 04 - Mineral wool, rock wool, insulation
- 05 - Tile, pipe, ceramics
- 06 - Unclassified

06 - INDUSTRIAL - PETROLEUM & GAS INDUSTRIES

- 01 - Oil-gas field operations
- 02 - Oil-gas transportation and storage
- 03 - Refineries
- 04 - Unclassified

07 - INDUSTRIAL - AGRICULTURE & FOOD PROCESSING

- 01 - Canning and food drying
- 02 - Citrus
- 03 - Seafood
- 04 - Sugar
- 05 - Unclassified

08 - INDUSTRIAL - UNCLASSIFIED

- 01 - Other food industries (bakeries, meat packing, etc.)
- 02 - Lumber industries (milling, etc.)
- 03 - Miscellaneous

10 - COMMERCIAL

- 01 - Commercial office buildings
- 02 - Process plants (cleaners, laundry, paint shops)
- 03 - Retail outlets (department stores, food stores, etc.)
- 04 - Unclassified

11 - INSTITUTIONAL

- 01 - Governmental operations
- 02 - Hospitals
- 03 - Penal institutions
- 04 - Educational institutions
- 05 - Unclassified

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